Scientific foundation on the Belgian simultaneous import limit

Roadmap towards 7500MW

13 May 2019

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Introduction

One of the important missions of a TSO is to manage system security, while at the same time promoting economic efficiency and accessibility of users to power markets. In this context, Elia is developing and operating its transmission grid in order to provide market players the opportunity to generate, consume, import and export electricity when and in the quantity that best fits their needs. While at the same time, these opportunities should not endanger operational system security. In doing so, Elia has determined a “Belgian Max import”, being a limit of simultaneous import in Belgium.

This BE Max import limit is determined by three different factors, namely the BE stability limit, the BE static current limit and external factors. Each of these factors individually have an important influence on BE Max Import, but must always be considered in combination to get a complete picture.

The present document focuses only on one factor limiting the BE Max import limit : the stability limit which is determined by static voltage and dynamic security issues. It is this stability limit that triggers the need for the use of an external constraint in the flow based day ahead capacity calculations.

In order to satisfy static voltage and dynamic security criteria (the BE stability limit), Elia makes use of an external constraint, set at 5500MW since June 2018. Before June 2018 the external constraint was set at 4500MW:

The purpose of this document is to provide a scientific foundation for the 7500MW BE stability limit. As requested by CREG in its decision (B)1814 on the application for approval of the proposal of NV ELIA SYSTEM OPERATOR for the adaptation to market coupling in the Central West Europe region following the integration of the German-Austrian bean border and the integration of the 20% minimum RAM rule, Elia needs to demand approval before the application of the external constraint with a justification for the applied value.

The first chapter describes the background and context of the use of the Belgian stability limit. Chapter 2 provides a general description of the methodology that is used to determine the value of this limit. The next chapter explains the result of the application of this methodology that will lead to the determination of the BE stability limit of 7500MW. Finally, Chapter 4 will explain what timings are foreseen to increase stepwise this limit in order to obtain the final value of 7500MW.

1 Context

2 Context

Since the beginning of market coupling, Elia has used a simultaneous import limit to maintain the operational system security. Since the start of Flow Based Day Ahead Market Coupling (FB DAMC), this limit has been translated into an "external constraint" in line with the approved methodology by CWE NRAs. Below figure provides an overview of the different values determined until present.

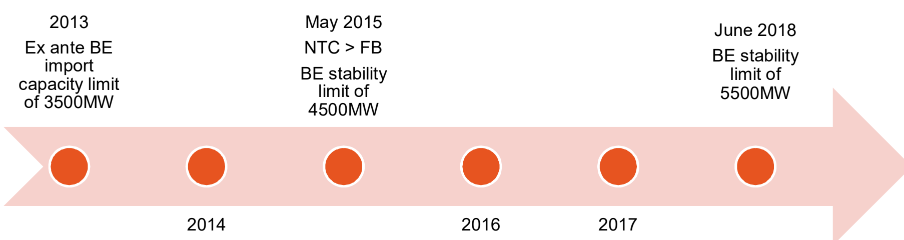


Figure 1 Evolution of BE stability limit

In chapter 3.3 of decision (B)1814, CREG deals with changes to external constraints. Concerning the value of the external constraint, CREG requests to provide further transparency and justification on the applied value by means of a scientific foundation.

Elia would like to stress that, although it is absolutely necessary to keep a BE import limit to not endanger operational security, Elia has always made the necessary precautions and investments to prevent as much as possible the real activation of this limit. As represented in Figure 2, since the go-live of the FB DAMC in May 2015 the BE stability limit of 4500MW/5500MW has never been limiting for the market since the effective import has never reached this limiting value. This is fully in line with our ambition to avoid that voltage stability would limit the market exchanges

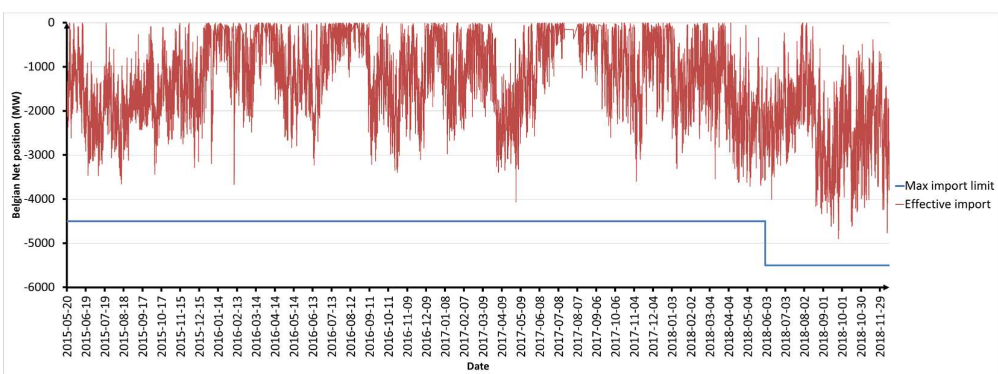


Figure 2: Evolution of the effective net position of the Belgian hub compared to the BE stability limit.

3 High-level methodology to determine the maximum BE stability limit

This chapter provides the high-level methodology to determine the maximum BE stability limit that ensures steady state voltage and dynamic voltage stability, in an all unit dispatch configuration.

The approach followed consists of 5 different steps, as represented in Figure 3:

1. Critical scenario building and selection;
2. Steady-state load flow convergence;
3. Steady state analysis;
4. Dynamic analysis;
5. Reactive power investments determination and localization optimization.

Figure 3: High-level methodology

3.1 Critical scenario building and selection

The determination of the critical scenarios to be investigated in more detail consists of three steps:

1. Probabilistic market study
2. Reactive power system analysis
3. Clustering and selection of critical planning cases

3.1.1 The probabilistic market study

This study consists of a Monte Carlo coverage of different climatological years and different generation unit dispatch (in function of average typical unit (un)availability), supposing that no predefined BE stability limit is limiting the operation of the market. One of the important inputs for this study is the expected generation mix and generation availability at the target horizon. These assumptions are based on the latest collected information available just before initiating the study. As an output result, a set of hourly profiles (65 x 8760hours) for each centralized power plant and the total aggregated profile per decentralized generation type is provided.

Based on these results, the 65 hourly profiles of **the total available reactive power control range** is computed with the assumption that each CIPU power plant can provide reactive power as per the requirement of the technical regulation or as per the existing contract for reactive power auxiliary services.

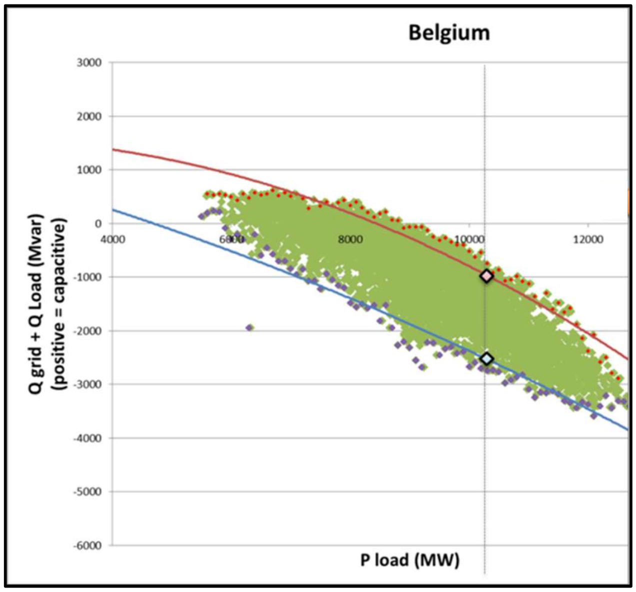


Figure 4: PQ graph for the Belgian system load (example of 2013)
(P stands for active power load (in MW) and Q for reactive power load/reactive grid losses (in Mvar))

Similarly to the generator output, the probabilistic analysis provides the most likely Belgian load active power profile. For this load profile, the historical active-reactive power load characteristics of the Belgian system is used to plot Figure 4. This allows to identify the minimal/maximal system needs (i.e. reactive power of the consumption as seen from the Elia grid and the reactive power consumption of the transmission grid elements) to be taken into account for the system analysis for each hour of the simulated target year.

3.1.2 Reactive power system analysis

In a second step, during the **system analysis**, the reactive power balance is made for each hour of the simulated target year by making the sum of:

1. the reactive power capabilities of the static shunt elements (shunt capacitors/shunt reactors), available at the target year
2. the reactive power capabilities of the power plants (i.e. the total available reactive power control range)
3. the reactive power needs of the Belgian system

An example of this calculation is represented in Table 1.

	ACTIVE LOAD (MW)	REACTIVE INJECTION (MVAR)	REACTIVE ABSORPTION (MVAR)
Generator Capabilities	6642	2091	913
Nuclear	4052		
Thermal	211		
Wind	508		
Solar	405		
Hydro	59		
Pump Storage	100		
CHP	1307		
Gross Load (+ loss) needs	12104	2528	-974
Export (+) / import (-)	-5462		
Balance	-5462	-437	1887

Table 1: Example of the reactive power balance calculation in the system analysis step

3.1.3 Clustering and selection of critical planning cases

In the third step, the hours of the simulated target year with the most critical reactive balances are filtered and clustered in specific scenarios (e.g. winter scenario, interseason high nuclear, interseason high RES, ...). Based on this **clustering and selection method**, the scenarios to be investigated in more detail are then selected (relevant clusters are considered and for each of those relevant clusters a relevant hour has been chosen).

3.2 Steady-state load flow convergence

The selected scenarios are translated into the full grid model for the considered time horizon. This grid situation is then optimized by using an Optimal Power Flow (OPF) algorithm that has the objective function to maximize the operational margin of reactive power on each power plant providing reactive power auxiliary services:

$$f(x) = \sum_{i \in G} \frac{(Q_i)^2}{(Q_i^{\max} - Q_i^{\min})}$$

The constraints of the Optimal Power Flow (OPF) function are:

- Minimum and maximum operational voltages for each Belgian substation respecting the operational criteria
- The reactive power capabilities of the power plants and the shunt elements
- A maximum cross-border exchange of 100Mvar to be in line with the agreed inter-TSO standards from the ENTSOe Operation Handbook

The control variables of this OPF function are:

- Tap changes on transformers (except PSTs)
- Power plant reactive power within its capability

- Position of switchgears of shunt capacitors and shunt reactors (ON/OFF)

If no OPF convergence can be found (meaning that the considered grid situation will not converge for AC load flow (ACLF) given the available control variables), this means that there are insufficient/not correctly located reactive capabilities available for that grid situation. This means that extra reactive power means should be added/relocated until OPF convergence can be obtained.

3.3 Steady state security analysis

The steady state security analysis consists of a contingency analysis for which the focus is on the obtained voltages after incidents. The considered incidents are:

- N-1 on all 380kV/220kV/150kV grid elements including the shunt capacitors/reactors
- any combination of those N-1 incidents with the loss of a power unit
- loss of a single 380kV bus bar.

The actual operational approach of managing reactive power and controlling the voltages exists of the combination of

- automatic voltage control of power plants (P>25MW)
- manual switching in/off of shunt elements (shunt capacitors or shunt reactors)
- manual changing the tap positions of transformers

Therefore the N-1 analysis checks whether no voltage issues (i.e. voltages outside the operational limits) occur immediately after the incident (only automatic voltage control of the power units) and 15 minutes after the incident (only limited manual actions on shunt elements/transformers).

If voltage issues are detected during this analysis new shunt elements have been added.

3.4 Dynamic analysis

The dynamic analysis consist of a Dynamic Security Assesment (DSA). During this DSA, in order to validate the dynamic behavior of the grid, two set of criteria are checked:

1. Fast and slow Transient overvoltages and undervoltages considering the fault ride through profile defined in the Belgian grid code as reference
2. Stability of the generators directly connected to the ELIA grid with a Pnom > 25MW, considering
   - Alternator voltage
   - rotor angular position
   - rotor speed

The assessment of those (in)stability criteria is done by simulating the following contingencies:

- Dynamic N-1 busbars 380 kV: Short-circuit on 380 kV Belgian busbar followed by busbar clearing 180ms after the short-circuit. The short-circuit on a grid element is eliminated by opening all equipment till reaching the first breaker. Note that the load transfer is not modelled. For each of the event, a 10-minutes dynamic simulation is ran in order to include the above mentioned automatic reactions triggered by the event

After the assessment of those (in)stability criteria, global system indicators are considered to determine the criticality of the considered situation:

- Number of refused cases: activation of dynamic criteria may lead to a stop and refusal of the simulated case (non-convergence of the situation after incident). The number of the refused cases will be monitored
- “Loss of Load” impact: The nodes which are violating the fast and slow transient voltage criteria are reported and weighted according to their voltage level. The sum of the weighted nodes will provide the “loss of load” impact.
- Interdependency level: After each contingency, the variation of reactive power produced in Belgium is compared with the variation of the reactive power on the tie-lines. The sum of contingencies where the tie-lines variation is higher than the Belgian variation is defining the interdependency level.

However, the above described dynamic analysis methodology is obtained on a deterministic base case, where load and generation are assumed to be well known. Furthermore, this methodology provides a binary output; the system is either secure or not secure. An additional valuable information would be the stability margin of the system. In order to partially answer this question, 2 types of stress are simulated:

- **Stress on the load:** each of the dynamic validation steps is not only performed for the load of the base case but also with increased values of the distribution loads to test robustness of conclusions with regards to load and dispersed generation forecast errors. The difference between that actual load value and the lowest load value for which dynamic instability is obtained will be called the “load margin”. The value of the resulting load stress will be monitored
- **Stress on the contingencies:** on top of the initial contingencies, additional events are simulated, i.e. dynamic N-1 on 150kV busbars 150. (Short-circuit on 150 kV Belgian busbar followed by busbar clearing 180ms after the short-circuit. The short-circuit on a grid element is eliminated by opening all equipment till reaching the first breaker. Note that the load transfer is not modelled. The number of 150 kV busbars which will lead to representative violation of the acceptance criteria will also give an indication of the stability margin of the system on the potential local impact. The number of refused 150kV busbar faults will therefore be monitored)

3.5 Reactive power investments determination and localization optimization

In this final step, also extra grid elements for reactive power management are taken into account. Based on the analyses of the first four steps, by considering different kind of technologies, different locations for extra elements and by considering the on-field constraints, a view on the needed grid reinforcements has been created, thereby optimizing over the different time horizons, so that the investments follow a certain logic and are also relevant on long term. This results in short term investments (to be taken into account for the ongoing assessment) and mid- to long-term investments (that can be taken into account in future evolutions of the BE stability limit).

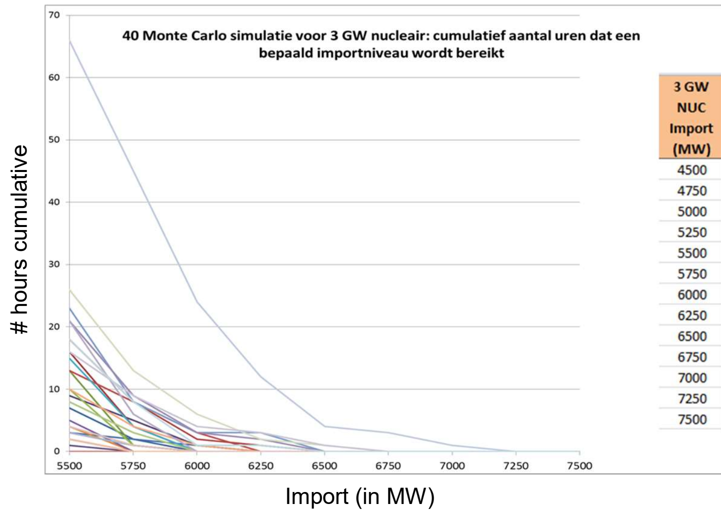
4 Analysis for the increase of the limit to 7500MW

In decision (B)1814 CREG requests to provide further transparency and justification on the applied value by means of a scientific foundation. In this chapter, the methodology described in Chapter 2 has been applied, leading to a new value of the Belgian simultaneous import limit of 7500MW that could be applied after the realization of the 2 HVDC interconnectors and the fulfillment of the 1st pack of the MVAR investment program, as communicated to the CREG in April 2018.

The post-HVDC situation has a big impact on the reactive power management needs and capabilities of the Belgian transmission system, since two HVDC convertor stations, one connected to Gezelle substation (NemoLink Limited) and one connected to Lixhe substation (ALegro), with each an automatic and continuous reactive power controlling capability of [-300Mvar,+300Mvar] become available for the Belgian system. The main driver for those investments was however triggered by active power exchanges and provides therefore the capability to increase the import of active power with 2000MW. As a consequence, it can be expected that some power units (with their reactive power capabilities) will no longer be available in certain scenarios. Hence, It becomes clear that those HVDC interconnectors will not only change the active power exchanges but also the way of managing the reactive power and voltage control. For this reason, the realization of the HVDC interconnectors has triggered to need for a new study to reassess the BE stability limit. The conclusion of this study is that this limit can be raised to 7500MW when certain conditions are met.

4.1 Critical scenario building and selection

A probabilistic market study of 40 Monte Carlo years for the time horizon 2020 has been run in order to determine the maximum import that can be expected for the post-HVDC time horizon. The analysis covers scenarios with 3GW of nuclear out of service, to cover for critical situations as experienced in 2014. Figure 5 reflects that when no predefined system limit has been assumed on the Belgian import, a maximum simultaneous import of more than 7000MW will very rarely be reached (1 hour in 40 Monte Carlo years). But even to overshoot this, for this study, it has been decided to investigate a scenario with a BE stability limit of 7500MW.



3 GW NUC Import (MW)	# Hours Cumulative P50	# Hours Cumulative P95	# Hours Cumulative P100
4500	125	237	350
4750	67	149	189
5000	34	92	102
5250	14	49	83
5500	4	23	66
5750	1	9	45
6000	0	4	24
6250	0	3	12
6500	0	1	4
6750	0	0	3
7000	0	0	1
7250	0	0	0
7500	0	0	0

Figure 5 Probability on the Belgian import level.

Based on a probabilistic market study of 40 Monte Carlo years for a time horizon of 2020, the reactive power system balance has been generated, taking into account the reactive capabilities of the ancillary service power plants from the Mvar tender. Out of those 40 x 8760 hours, 3 critical scenarios have been considered (Table 2) with the best assumptions that could have been foreseen for that time horizon on the moment of the study execution. Amongst those scenarios, the most critical scenario for a post-HVDC situation is scenario 3. In this scenario it has been assumed that half of the nuclear power park is not available. The assumptions are

- Peak Load 14,5GW + 1,9Gvar, which represents the P95 value for the active load from the 40 Monte Carlo years
- 7.5GW import, of which 2GW over the HVDC interconnectors
- 3GW nuclear power plants available in the initial grid transmission system situation. (Highest criticality is when remaining nuclear power plants are all at the same location in the grid)
- 1GW of Local Renewable Energy Sources (RES) or small cogeneration production (which have no or very limited reactive power capabilities)
- 2.3GW of offshore wind production
- 0.7GW of Large cogeneration production or CCGT production (which have standard reactive power capabilities)

Post-HVDC study			
	WINTER Scenario 1	WINTER Scenario 2	WINTER Scenario 3
Gross consumption	14.5GW + 2Gvar	14.5GW + 2Gvar	14.5GW + 2Gvar
Import (on HVDC)	5.5GW (0GW)	6.5GW (1GW)	7.5GW (2GW)
Nuclear	5GW	4GW	3GW
RES	1GW	1GW	1GW
Offshore Wind	2.3GW	2.3GW	2.3GW
CHP + CCGT	0.7GW	0.7GW	0.7GW

Table 2 Analyzed scenarios for 7500MW import

The determination of the extra investments for reactive power management and voltage control will be determined on this latter (most critical winter) scenario.

4.2 Steady-state load flow convergence

For the most critical scenario (scenario 3), no extra shunt elements (or others) had to be integrated into the grid model in order to obtain an OPF optimized load flow that converges in AC.

4.3 Steady state security analysis

For the most critical scenario (scenario 3), steady state voltage violations were detected on the 380kV backbone. However, it has been observed that a large part of the reactive power capabilities of the nuclear power plants has already been used to set acceptable voltages in N and only a limited part of the reactive power capabilities (called the operational margin of reactive power) is therefore to cover for N-1. By adding extra shunt capacitors (i.e. 600Mvar extra) well distributed over the Belgian system, the part of the reactive power from power plants used to set acceptable voltages in N is reduced and the operational margin of reactive power is increased sufficiently to cover for N-1 issues. This behavior has also been observed in the dynamic analysis.

To control this assumption, another run of the steady state security analysis has been performed with the assumption of 600Mvar of extra shunt capacitors. In this run, no voltage steady-state voltage issues have been detected.

4.4 Dynamic analysis

The run of the dynamic system analysis results in a violation of acceptance criteria in all 3 scenarios. To overcome these violations, additional Mvar resources are needed.

No fast transient voltage issues are observed, so consequently, there is no explicit need for fast voltage support mean such as a STATCOM or Synchronous Condenser. Concerning, slow transient voltage issues, these are observed if dynamic Mvar operational margins of reactive power are not sufficiently well distributed throughout the Belgian system. Also the interdependency with neighboring system is increased if these operational margins of reactive power are not sufficiently well distributed.

The dynamic analysis has shown that 600Mvar capabilities should be made free on the power plants in order to cope for slow dynamic issues. In order to free up this margin, extra shunt capacitors can be placed in the grid (cfr. steady-state security analysis).

To control this assumption, another run of the dynamic system analysis has been performed with the assumption of 600Mvar of extra shunt capacitors. In this run, no dynamic voltage violations have been detected.

4.5 Reactive power investments determination and localization optimization

The 600Mvar investments in shunt capacitors to free up some operational margin of reactive power on the power plants need to be installed on or close to the 380kV/150kV transformer stations in the following regions in the grid.

- Two 150kV shunt capacitor of each 75Mvar in the Ruien region
- One 150kV shunt capacitor of 75Mvar in the Brussels region
- One 150kV shunt capacitor of 75Mvar in the Rodenhuize region
- One 150kV shunt capacitor of 75Mvar in the Liège region
- One 150kV shunt capacitor of 75Mvar in the Avelgem region
- One 380kV shunt capacitor of 130/190Mvar in the Antwerp region

All those shunt capacitors together makes a total of around 580Mvar-640Mvar to cover for the need detected in the previous analyses.

4.6 Conclusion

The above analysis shows that for a grid/system perspective post-HVDC (described in chapter 3), after the realization of the Nemo and Alegro HVDC connectors, an external constraint of 7500MW can only be accepted (under the "best" hypotheses), when extra investments in reactive power management and voltage control assets are done. Only then, it is 99.9% sure that an import of 7500MW would not lead to possible steady-state and dynamic voltage issues. Those needed investments are:

- the Alegro HVDC convertor station
- extra shunt capacitors for 600Mvar extra reactive power injection

5 A stepwise approach to evolve from 5500MW to 7500MW

In June 2018, Elia had increased the external constraint from 4500MW to 5500MW. The document “*Scientific foundation on the BE stability limit – Increase of June 1st 2018 to 5500MW”* justifies this decision and describes the application of the high-level methodology from chapter 2. The outcome of this analysis was that from the reinforcement of the Stevin corridor, and without a need for extra investments in reactive power management and voltage control assets, an external constraint of 5500MW would not lead to possible issues of steady-state and dynamic voltage issues.

Given the conclusion of the above analysis and the fact that the needed investments to be able to increase the limit to 7500MW may still take some time, Elia has looked into how the external constraint can be stepwise increased before all those investments are made. Both the perspective of security of supply and facilitating the market have been drivers to this. In this chapter, Elia will focus on 2 main points:

1) Planning of the Mvar investment program
2) Monitoring of the hypotheses between the post-Stevin study and the post-HVDC study, and this by making the reflection to the actual reality.

This is further described in the next paragraphs.

5.1 Planning of the Mvar investment program

Three 150kV shunt capacitors of each 75Mvar, thus a total of 225Mvar are foreseen to be realized once the Alegro HVDC connector will become operational into service.

The realization of the remaining shunt capacitors to reach 600Mvar, as identified in the study, is foreseen to be realized at the end of 2022.

5.2 Monitoring of the evolution of the reactive power consumption hypotheses

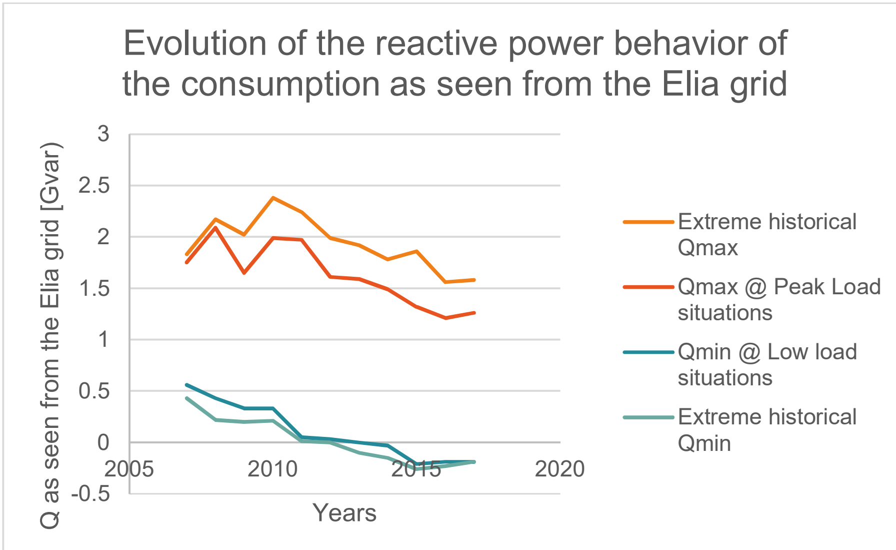


Figure 6: Evolution of the reactive power consumption as seen from the Elia grid.

Figure 6 shows the monitoring of the evolution of the reactive power consumption. The reasons for an increasingly capacitive behavior could be explained by

- the replacement of directly connected induction motors by power-electronic fed drives which are running at almost unity power factor;
- the evolution of the lighting towards more led or power electronic based appliance and
- the effect of decentralized generation which is located very close to the load within the distribution network. This results in a lower loading of the distribution network ➔ this network gets a more capacitive behavior ➔ the gross load stays the same (lower net load due to DG) but the net load has a more capacitive behavior as seen from the Elia connection point.

However, the evolution of the reactive power behavior of the consumption needs to be further monitored in order to plan the needed investment and to define a simultaneous import limit which ensure steady state voltage and dynamic voltage stability for the future years.

This change in reactive power was expected by Elia as shown by comparing the difference between the hypothesis made in the post-Stevin study (14GW; 3Gvar) and those made in the post-HVDC study (14.5GW; 2Gvar). However, one can observe that this change was faster than foreseen and therefore Elia proposes a step-wise approach to increase the simultaneous import.

5.3 Stepwise approach to increase from 5500MW to 7500MW.

The values obtained from the post-Stevin study and post-HVDC study are determined based on a quantitative assessment using careful defined hypothesis on reactive power system needs and by following the methodology described in Chapter 2. Such an approach is also complemented by a careful monitoring of the evolution of the hypotheses, in order to adapt the conclusions of the studies based on the effective system needs and in order to trigger, in case needed, a new study. The results of this monitoring task have shown that, since the realization of the post-Stevin study, the reactive power behavior of the consumption as seen from the Elia grid shows a trend towards a more capacitive behavior in case of high consumption.

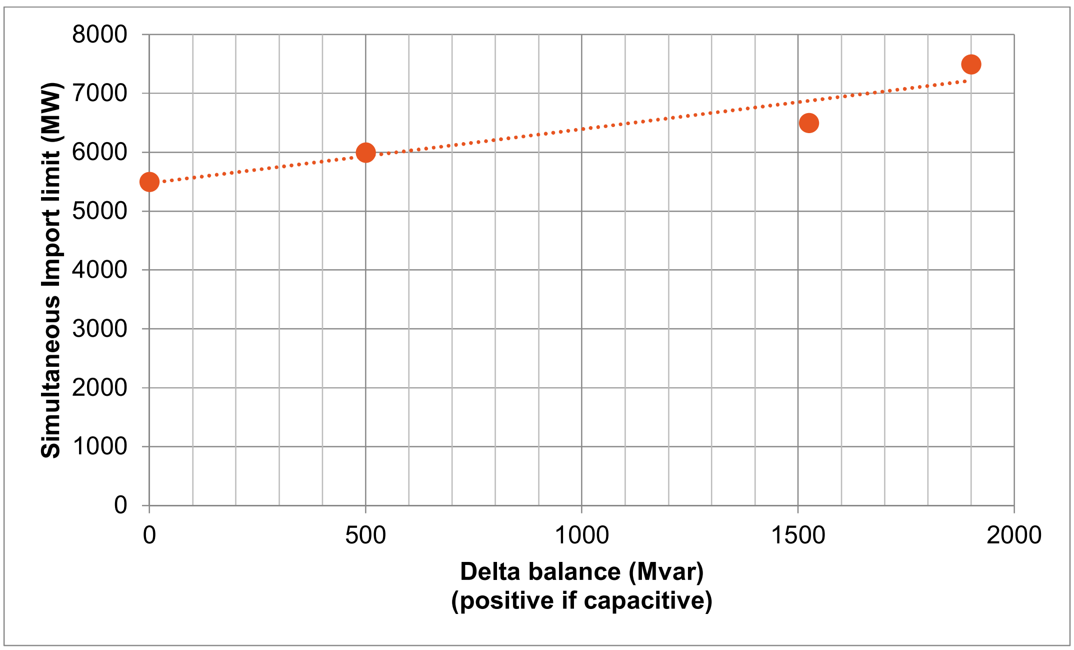
Based on this, Elia has reassessed the post-Stevin study results and will apply a stepwise approach to increase from 5500MW to 7500MW. In order to do so, Elia will use a more qualitative reasoning to demonstrate that stepwise increasing from 5500MW to 7500MW is possible without unacceptable risks. This qualitative approach considers new facts (i.e. actual Belgium reactive power consumption is lower than the one used in the post-Stevin study) which indicate that the operational margins of reactive power increase which might allow for more active power import capability than 5500MW. However, at the other side, the foreseen reinforcements (shunt capacitors) from the post-HVDC study will not all be finalized at the go-live of Alegro. Remark that the monitored trend of the reactive power load has already been taken into account in the hypotheses of this latter study. This indicates that (at the go-live of Alegro) the operational margin of reactive power will be lower than the one foreseen in the post-HVDC study, which might allow for less active power import capability than 7500MW. In order to limit high uncertainties/risks of sudden significant changes in operational conditions, it is recommended to proceed a stepwise approach and learn from the previous step before deciding to go to the next one. As no real risk have been observed so far for the increase from 4500 towards 5500MW, it is possible to further increase.

At this moment the perspective is to move from 5500MW to 7500MW in the following steps:

1) From beginning 2019 an import of 6000MW can be allowed by considering the reactive power balance due to the overestimation of the Belgium reactive consumption.
2) From the go-live of Alegro an import of 6500MW can be allowed by considering the reactive power balance due to the extra investments already realized (with Alegro capabilities) at that moment
3) Once all 600Mvar investments are realized an import of 7500MW can be allowed by considering the reactive power balance due to all investments

Finally, also an interpolation approach is considered to show similar results as for the qualitative approach. In this approach it is possible to monitor at one side the change in needs (delta reactive power load, cfr. hypotheses) and at the other side to monitor the change in reactive power control possibilities (Extra investments/HVDC capabilities). By making the delta of both, it is possible to come with an estimated value for the external constraint via a linearization.

	Post Stevin study		Post-HVDC study	
	Post Stevin study & associated investments	Change in load behavior	Go-life Alegro	Post-HVDC study & associated investments
time horizon	mid 2018	mid 2019	mid 2020	end 2022
Delta reactive power load (Mvar) (positive if capacitive)	**0**	*500*	*0*	**0**
Extra Generator & HVDC capabilities (Mvar)	**0**	*0*	*300*	**300**
Extra investments (Mvar)	**0**	*0*	*225*	**600**
Delta balance (Mvar) (positive if capacitive)	**0**	*500*	*1525*	**1900**
Simultaneous Import limit (MW)	**5500**	*6000*	*6500*	**7500**



5.4 Remark on the qualitative and interpolated approach

The qualitative and interpolated approach as described above, makes use of a linearization/interpolation. However the optimizations on reactive power control and voltage, made in the quantifying methodology, are in fact non-linear. Elia assumes that as long as the considered study scenarios (in this case adapted by the change in assumptions) do not differ too much from the point around which the optimization has been made, a linearization is acceptable (possibly with a slightly higher risk). It should be stressed that such an approach cannot be used for long term horizons (and/or to determine higher import values than 7500MW), since this would

1) need an extrapolation and
2) have strongly different study scenarios (e.g. post nuclear phase out)

5.5 Conclusions

The study here described leads to a stepwise approach for increasing the BE stability limit that has been integrated in the CWE FB DAMC. In a first phase the BE stability limit will be increased from 5500MW to 6000MW as from May 25th, 2019. This new value is the maximum value that can be achieved since it requires

- the confirmation in reality of the adapted hypothesis on reactive load or
- the realization of new investments in reactive power control assets (foreseen at the go-live of Alegro)

Thanks to this confirmation of adapted hypothesis, the previous static current limit of 5500MW can be increased to 6000MW. Without this confirmation this increase would need additional investments (e.g. at the go-live of Alegro).

Annexe 1: (in)stability criteria

Fast and slow Transient overvoltages and undervoltages are assessed in 380kV, 220kV, 150kV, and 70kV grids as shown in Figure 7. This figure illustrates the thresholds (hatched area) which should not be crossed by the transient voltage after a major disturbance (short-circuit or tripping of an element). The transient voltage evolution includes the effect of all automatic actions such as protection tripping. It should be noted that even though the low voltage threshold after 10s seems stringent, due to the typical behaviour of the loads that are progressively recovering their active power after an event, if this 10s-criterion is not met, the 10min-criterion will not be met either. Therefore keeping this criterion would allow reducing the simulation time. But, to identify large scale effects, the low voltage threshold after 10s has been deactivated.

As also illustrated in Figure 7, this criteria can be activated either during the voltage restoration phase, represented by the 1,5 second following the fault elimination (red curve): We speak then about Fast transient under/over voltage or later on, when load is recovering (blue curve): We speak then about Slow transient under/over voltage. Once Fast or Slow transient under/over voltage criteria is activated, the simulation is stopped and the case is considered as refused. Low or high voltage violations corresponding to the 10s criteria are monitored as Voltage Steady-state alarms at the end of the simulation.

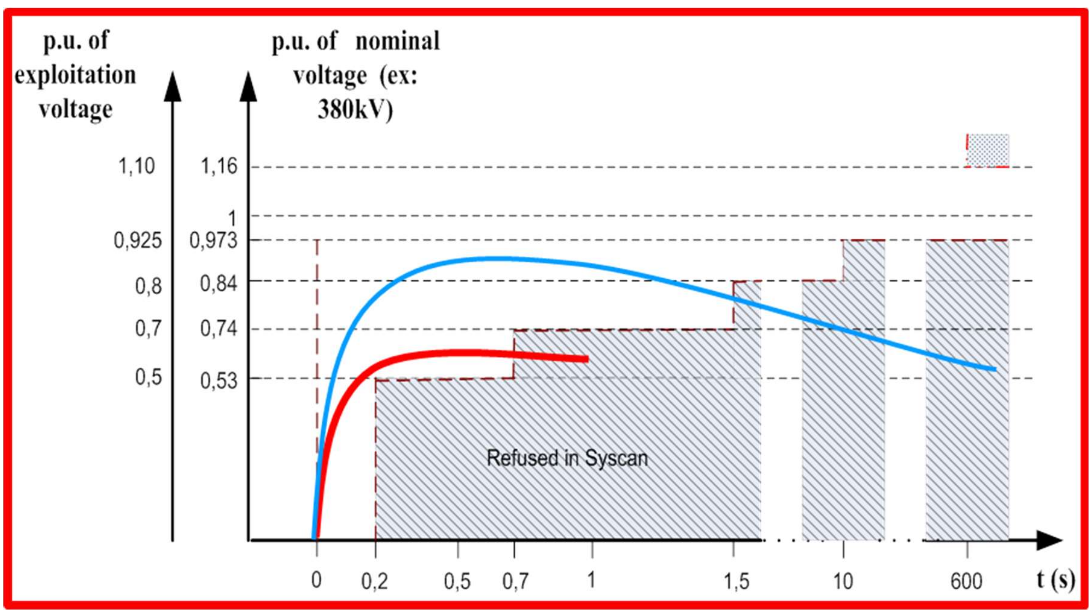


Figure 7 Dynamic acceptance criteria - Hatched area should not be crossed by the transient voltage after a major disturbance. Illustration of Fast and Slow transient undervoltage

Power plants represented by a detailed model are considered as **losing their synchronism** after fault elimination when their angular position is deviating more than 360° from a reference position taken from a faraway equivalent unit. Once activated, the simulation is stopped and the case is considered as refused.

Power plants represented by a detailed model or with Pn> 25MW will be disconnected once the **voltage at alternator side or his speed is going outside their technical capabilities**. If not known, required Belgian grid code capabilities will be considered. Once activated, the generating unit is disconnected and the simulation is not stopped. The lost generating units will be monitored as alarms at the end of the simulation