PUBLIC CONSULTATION

MOGII System integration study

June 8, 2020

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Executive summary

The planned installed capacity of wind farms in the Belgian offshore area by the end of 2020 amounts to 2.3 GW. The Belgian Government has established a framework for a 2nd wave offshore capacity of up to 2.1 GW. The additional capacity is assumed to be commissioned between 2026 (up to 700MW) and 2028 (up to 1400MW). The resulting offshore production profiles and forecast errors are expected to impact the system imbalance in normal and extreme weather conditions (fast wind variations and storms).

This study aims at analyzing the impact of additional installed offshore capacity on the system and to formulate recommendations. The present document is the first part of a full report which will be delivered on December 23, 2020.

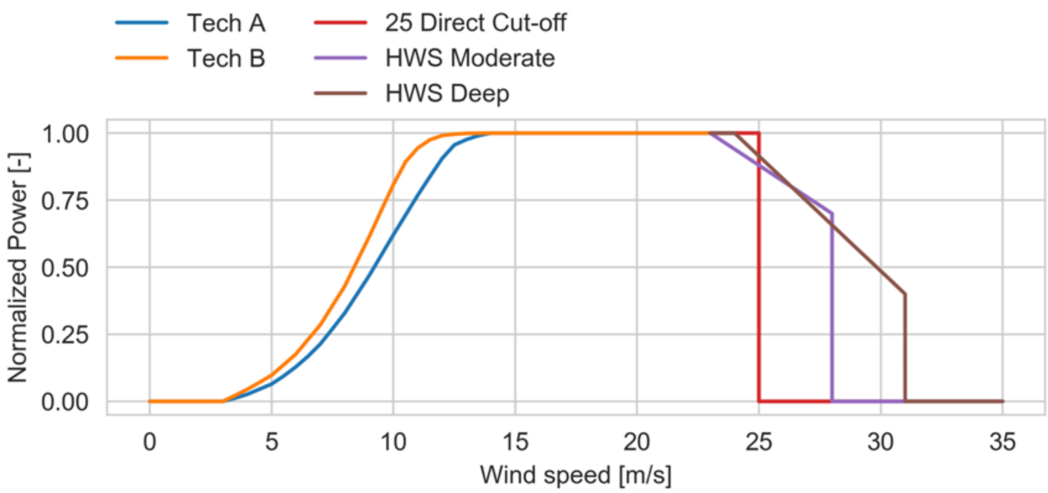
As these recommendations could include operational or technical constraints for the wind parks or concerned BRPs, they must be clarified before the tendering process, which is planned in 2023. A consequence of this approach is that assumptions need to be defined, which leads to uncertainties in the final results. For these reasons, the objective of the project in 2020 is establish a list of mitigation measures as exhaustive as reasonably possible and to evaluate the effectiveness of these measures in addressing the challenges identified in the study as well as their impact for the BRPs and for the future wind parks. Taking into account the uncertainties remaining at this stage, Elia is willing to engage in a discussion with stakeholders on the assumptions defined in the study, the methodologies used and the impact of the mitigation measures.

It's to be noted that the new mitigation measures should either not be applied to the existing parks, either not have a direct financial impact on the existing parks

The first step of the study is to **evaluate the future offshore generation profiles**. This part of the study has been realized with the support of an external consultant (DTU).

Scenarios with different offshore wind turbine technologies and installed capacities were built and discussed with stake-holders during workshops[1].

[1] The workshops took place on the 23rd of January and on the 9th of March. The material from the workshops is available on Elia's website



Power curves for assumed technology scenarios and storm shutdown scenarios

Considering the expected impact of additional offshore wind capacity on the grid, it is of particular importance to appropriately model the future offshore generation profiles, taking into account the geographical smoothening between the parks, as well as the wake effects within the parks and between the parks. DTU developed the methodology to simulate the generation profiles and validated the models based on measurement data from Belgian wind parks.

As the model validation showed satisfying results, DTU simulated the time series and calculated statistics for analyzing future extreme events (“rampings” due to fast wind variations and storms) and forecast errors.

A major conclusion of the study is that it is possible to lose the full installed capacity due to an extreme storm event. This is true for all scenarios on installed capacity and all the technologies assumed for the future wind parks. However, technologies allowing a progressive shutdown in high wind conditions are shown to have a positive impact on the frequency and the speed of shut-downs.

The analysis also showed that, for a 4.4 GW installed capacity, ramping events of more than 4GW in one hour time without a storm are possible, even though there are unlikely. Next to these most extreme events, ramping events of more than 2.0 GW in 1 hour time are to be expected about 7 time a year and ramping events of more than 2.5 GW about 1 to 2 times a year, on average. Ramping events of more than 3.0 GW are expected once every 3 years.

Finally, statistics were provided on the system imbalances, the individual BRP’s imbalances and the forecast errors based on data from the real system operation in 2018 and 2019. A main conclusion is that, at least until end of 2019, significant differences between BRPs were observed.

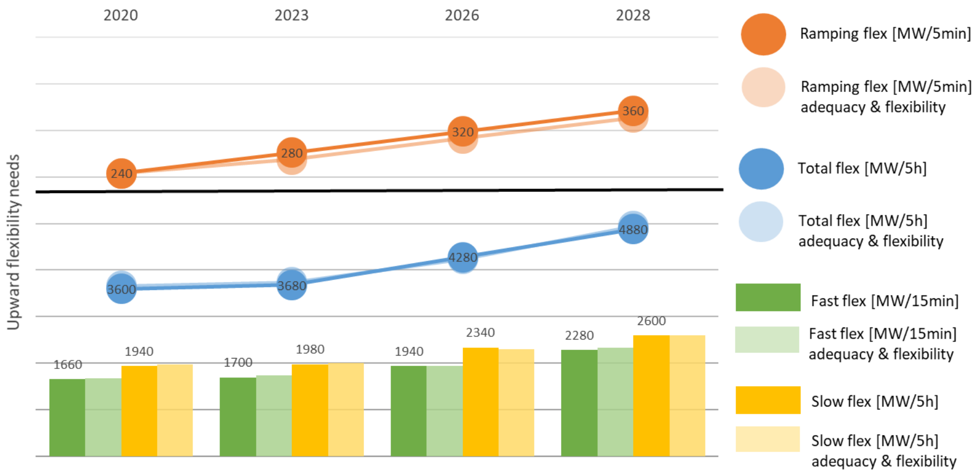
Impact of the 2nd wave offshore capacity on the system’s flexibility needs

In this study, an update of the flexibility needs is conducted based on new information concerning the estimated installed offshore generation capacity in 2026 (3.0 GW) and 2028 (up to 4.4 GW). In addition, specific high resolution time series representing Belgium’s offshore wind power generation and forecasts in 2026 and 2028 were provided by

DTU to assess the impact of unexpected variations on the systems' flexibility needs and Elia's reserve capacity requirements. This update allowed to better capture the effect of intra-15' variations on the flexibility needs, as well as the effect of smoothing of variations and prediction errors over larger geographical areas.

Based on the methodology used and described in the latest adequacy and flexibility study, the relevant scenarios were re-assessed towards 2026 and 2028. It is concluded that the trends and conclusions of the study are confirmed concerning the ramping flexibility (to react on minute basis, up to 5 minutes), fast flexibility (to react fully in 15 minutes) and slow flexibility (to react fully in 5 hours). It is observed that the increase in flexibility needs in 2026 and 2028, partially explained by a larger offshore generation capacity in 2026 and 2028 as formerly foreseen, is, to a certain extent, compensated by using the forecast errors calculated with the data provided by DTU. This can be explained as these data better take into account the geographical smoothing in comparison to the previous extrapolations of Elia's available data based on the 1st wind parks. This being less the case for the ramping flexibility where this effect is reduced by a slight increase in the flexibility needs due to increasing the resolution for the forecast error variations from 15' to 5'.

Despite this effect, the former approach of upscaling Elia's 15' forecast errors and generation variations was a good approximate for analyses concerning flexibility and reserve capacity requirements. It is also expected to further improve along with the increased offshore generation capacity to be observed.



Overview of the updated upward flexibility needs compared to the latest adequacy and flexibility study (same trends are observed for the downward flexibility)

The flexibility needs should be compared to the available flexibility means but as the needs are expected to remain relatively stable, no new simulations or updates have been conducted. The adequacy and flexibility study already concluded that if the system is adequate, sufficient flexibility will be installed in the system to cover the flexibility needs, although it will not always be operationally available when needed. This means that upfront reservations (by BRPs or Elia) will remain necessary. This is the case for upward flexibility and also to a minor extent for downward flexibility. Note that new technologies such as decentralized storage and demand response are found to contribute in increasing extent to provision of the flexibility means.

Available flexibility means are investigated during periods with high predicted wind power generation which is particular relevant for storm and downward ramping events. It is found that towards 2028, additional fast and even the ramping flexibility might be found through remaining cross-border capacity after the intra-day during periods with high wind. However, although the remaining cross-border capacity may in 2026 and 2028 be of lesser constraint during these periods, the available volumes which can be accessed in the balancing time frame trough the balancing energy exchange platforms MARI and PICASSO are subject to large uncertainties.

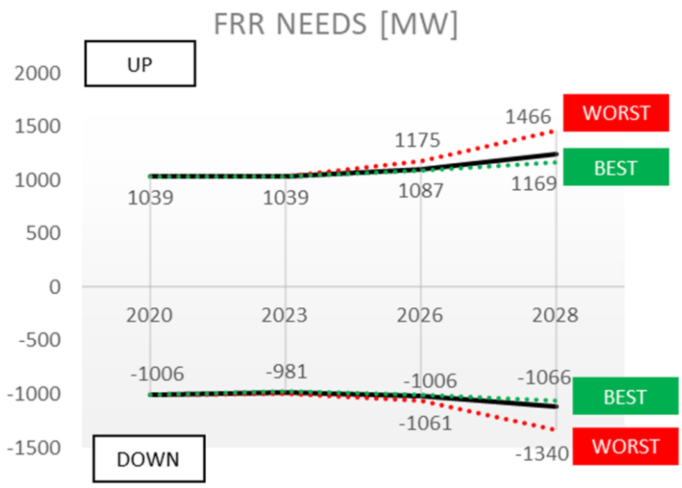
Impact of the 2nd wave offshore capacity on Elia's reserve capacity needs

In addition to an assessment on flexibility, an assessment is made of the impact on Elia's FRR reserve requirements (FCR outside the scope of this study as dimensioned on European level). Besides the above-mentioned scenarios concerning Belgium's generation fleet, different cases are made concerning the ability of the market players to deal with future portfolio and system imbalances caused by offshore prediction errors and variations.

By means of these scenarios, historic LFC block imbalances are up-scaled, taking into account forecast errors of incremental renewable generation (offshore, onshore and solar) together with forced outage risks of power plants and Nemo Link. The current dynamic dimensioning methodology is applied on this up-scaled data to make projections concerning the future average FRR needs in 2026 and 2028, as well as the expected FRR needs variations.

Results in the figure below show the expected average up- and downward FRR needs towards 2028 are expected to increase from 1039 MW and 1006 MW in 2020 towards respectively 1246 MW and 1111 MW in 2028. This observation is partially explained by the new offshore generation capacity and is at least valid in a reference case where the market's ability to cover forecast errors and portfolio imbalance keeps improving, in line with Elia's measures providing tools and incentives for BRPs to balance their portfolio, as well as increasing flexibility installed in the system.

FRR Needs [MW]	2020	2023	2026	2028
UP reference	**1039**	**1039**	**1104**	**1246**
worst	1040	1042	1175	1466
best	1039	1039	1087	1169
DOWN reference	**1006**	**981**	**1017**	**1111**
worst	1008	992	1061	1340
best	1006	977	1006	1066



Overview of the results of the average up- and downward FRR needs towards 2028 in reference case and worst / best case concerning the performance of the market to deal with unexpected variations of renewable generation

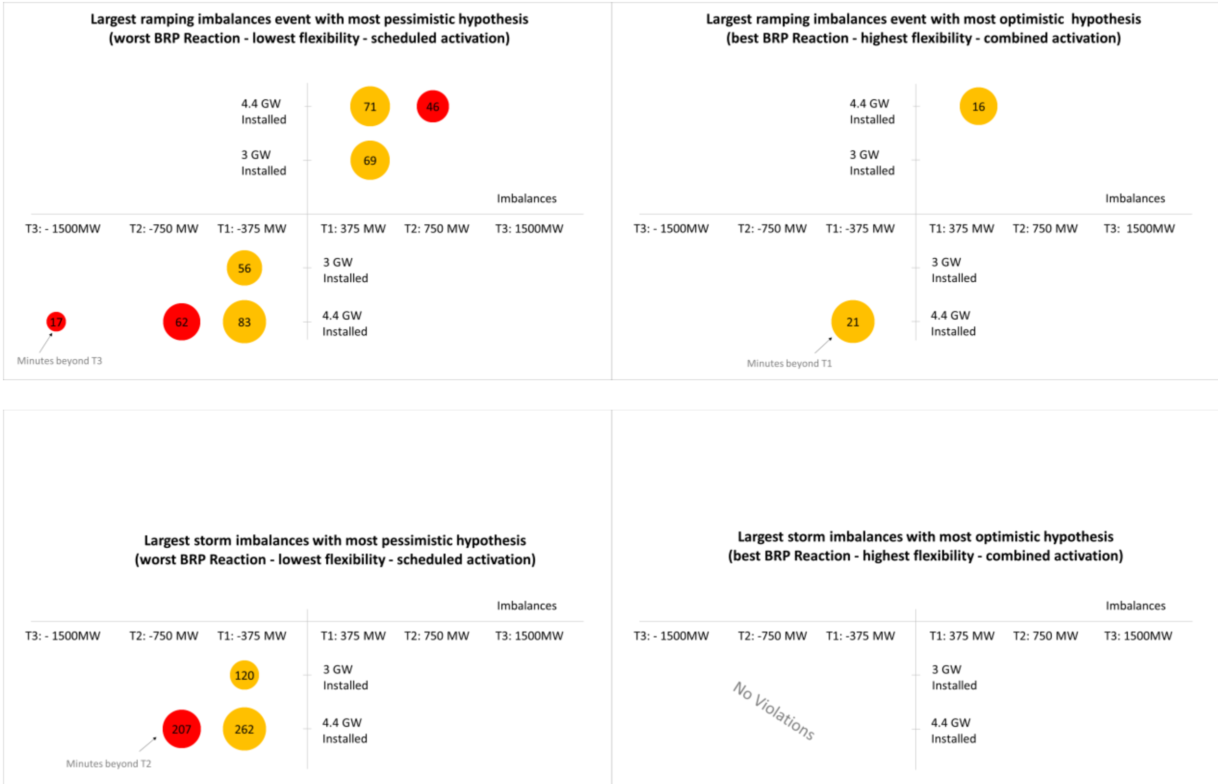
It is shown that the impact of market performance can have a substantial impact, i.e. with a difference of average FRR needs up to 300 MW between a worst and best case. Note that the final dimensioning is conducted day-ahead, based on machine learning algorithms and historic system conditions and that market performance will automatically be taken into account in the dimensioning. Towards 2028, the dynamic behavior is found to increase substantially with larger variations between minimum and maximum FRR need, i.e. between 1000 MW and 1600 MW for upward FRR needs, and 600 and 1700 MW for downward FRR needs.

Finally, the split has been made between aFRR and mFRR needs based on the current method for aFRR dimensioning, as these values are used in the dispatch simulations. Note that in parallel of this study, a new method is being investigated to improve the aFRR dimensioning methodology.

Impact of the 2nd wave offshore capacity on real-time system operations

In order to evaluate the possible impact on real-time operation, a set of simulations have been conducted using historical ramping and storms events while taking into consideration several sensitivities including reserve activations (scheduled/slower ⇔ direct/faster activation), available FRR means (4 different levels from low to high) and possible BRP reaction (worst case ⇔ best case) scenarios. This means that for different levels of installed capacity 32 different combinations have been simulated.

The analysis identified several combinations (both for the 3.0 GW and the 4.4 GW installed capacity) where the validation criteria to ensure secure system operations are violated. If we look at the high level summary of the results in the figure below, we can see that, for the most pessimistic combination of assumptions, large imbalances of long duration occur both for the 3.0 GW and the 4.4GW installed capacity. Looking at the combination of the most optimistic assumptions for all parameters the results looks much better, however, for the 4.4GW installed capacity violations still occur.



Summary of the violations observed in the simulations

It's fair to say that neither the most pessimistic nor the most optimistic cases are the most likely to happen, the truth will be somewhere in between those 32 different possible combinations depending on the BRP reaction, liquidity and speed of reaction. The most important insights of our simulations show that:

1) It's not a surprise that the scenarios with 4.4 GW installed capacity represent the highest risks, not only in terms of largest imbalances, but also in terms of long-lasting deviations.
2) The BRP behavior has a significant impact on most of the results, even though it might sound like kicking in an open door, all positive measures taken by BRPs can only reduce the need for Elia to fall back on mitigation measures in the future.[2]
3) It is confirmed that in case these violations would materialize (depending on the evolution of the assumptions in the future) they will require mitigation measures. Either to ensure that the optimistic assumptions can be guaranteed and/or to close the remaining gap.
4) Storm events, specifically for the 4.4 GW scenarios, resulted in extremely long and large violations in the scenario with the pessimistic assumptions, specific attention is required to mitigate this storm risk.

Based on the analysis of the results and their sensitivities, effective mitigation measures can be found by

- Reducing the origin of the deviations at the source and/or
- Increasing the availability of liquidity (in Belgium or abroad) and/or
- Increasing the reaction speed for the activation of said liquidity (by BRPs and/or Elia).

Finally, Elia established a **preliminary list of potential mitigation measures** in order to initiate disucssions with stakeholders on this topic. Each mitigation measure adresses one or more challenges identified in the analyses described above. The measures are divided in 3 groups:

- The existing mechanisms that are expected to have a positive impact on the system imbalance. Their effect will be further monitored in the coming years.
- Actions that need to be investigated by Elia. Those could potentially have a positive impact in the medium to long term and require further development in the coming years before their effect can be quantified.
- The last group of measures imply technical and operational constraints for the wind parks and/or the BRPs.

	Mitigation measures	**Up ramps**	**Down ramps**	**Storm cut-out**	**Storm cut-in**	**Reserve needs**
Existing mechanisms	Current storm procedure			X		
	Alpha	X	X	X	X	X

[2] It is important to remind, that beyond dedicated mitigation measures, Elia will pursue further improvements as the availability of good price signals, balancing market integration, market facilitation and stimulation of reactive balancing.

	Coordination of cut-in phase				X	
Actions to be investigated by Elia	Incentivize reactions to real-time prices	X	X	X	X	X
	mFRR activation triggers	X	X	X	X	
	Enhanced forecast functionalities	X	X	X	X	X
Measures implying constraints for wind parks and / or concerned BRPs	High wind speed technologies			X		
	Preventive curtailment of wind parks			X		
	Ramping rate limitation	X	(X)	(X)	X	
	Coverage of imbalances by BRPs	X	X	X	X	X

(X): apply only in cases of voluntary production decrease.

Stakeholders are welcomed to provide their suggestions and feedback on the present report in a public consultation from June 8, 2020 to July 8, 2020. Those will be taken into account when defining the next steps towards the 2nd consultation, planned to start on October 1, 2020. The final report will be published on December 23 the latest.

1. Introduction

The planned installed capacity of wind farms in the Belgian offshore area by the end of 2020 amounts to 2.3 GW. The impact of variations in offshore wind power parks production due to too high wind speed (hereafter also defined as “storm events”) or sudden changes in wind power or direction (hereafter also defined as “ramping events”) on the balancing performance of BRPs and hence the residual imbalance to be resolved by Elia has been evaluated in a previous study[3]. As a conclusion of the study, Elia developed:

- A dedicated storm forecasting tool to improve the forecast accuracy of these specific events
- Operational procedures between ELIA and BRP’s responsible for offshore production to coordinate actions and communication when a storm event is detected

These developments are further explained in the design note[4]. The solution implemented is valid for the expected 2020 offshore installed capacity. However, additional measures might be necessary for additional capacity that would be installed after 2020. The main reasons for that are the following:

- The operational procedures referred to above, in particular the fallback process which is iniatied when the volume not covered by the BRPs exceed the available reserves, rely on the availability of not running slow-start units in the Intraday timeframe. While it can reasonably be assumed that those units will be sufficiently available to cover this residual risk for an installed capacity of 2.3 GW, the volumes that would have to be available with an extended capacity are potentially much higher.
- Next to the storm events adressed in the current design, an extended offhsore capacity will also increase forecast errors and ramping events, which is expected to have a negative impact on the system imbalance.

In the Marine spatial planning 2020-2026, the Belgian minister competent for the North Sea has established the framework for an additional production zone of 281 km² (at the frontier with France), in addition to the existing production zone of 225 km² (at the frontier with the Netherlands). This new zone, illustrated in Figure 1, will allow up to 2.1GW additional installed capacity, which is expected to be commissioned between 2026 and 2028. The present study assumes that the additional capacity installed will be offshore wind power.

[3] OFFSHORE INTEGRATION STUDY: Analysis, benchmark and mitigation of storm and ramping risks from offshore wind power in Belgium. Elia, 2018. https://www.elia.be › elia › 2018-study-report-on-offshore-integration_en

[4] OFFSHORE INTEGRATION DESGIN NOTE. Elia, 2019. https://www.elia.be › elia-site › role-of-brp › brp-pdf-document-library

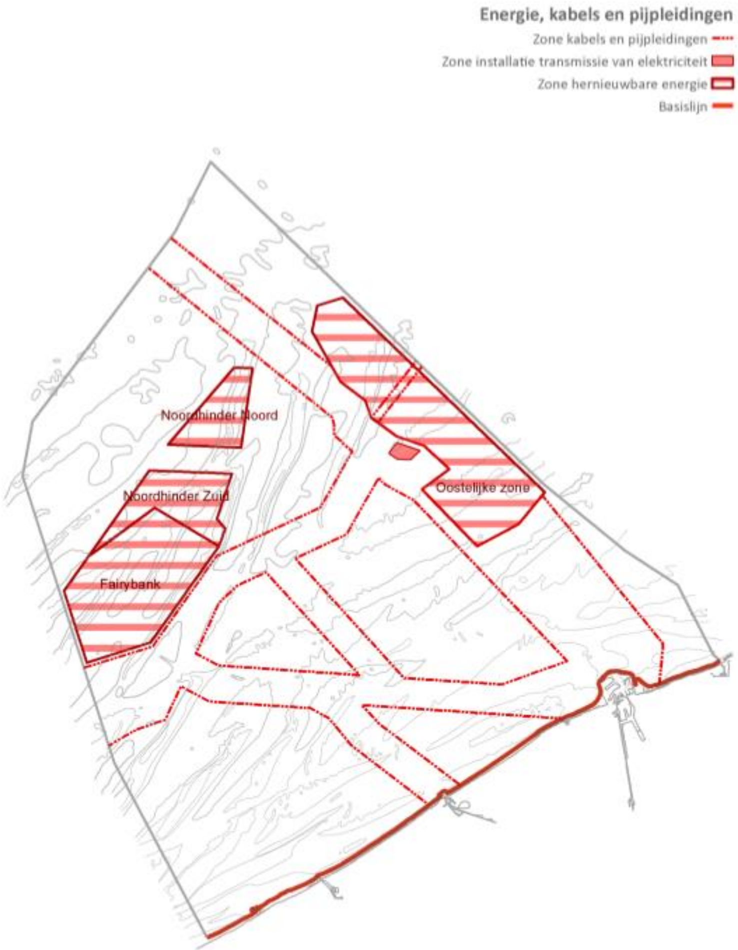


Figure 1: Existing area ("Oostelijke zone") and new area ("Fairybank" and "Noordhinder") for renewable energy in the Belgian North Sea

Two specificities related to the Belgian production zone are to be noted:

- In comparison with offshore production zones in other LFC blocks, the existing Belgian offshore production zone has a very high density, even when including the new area. This leads to a higher variability in the power injected in the grid in case of extreme wind variations and storm events, as geographical smoothening is not as high as in situations where the production zones are spread over a wider area.
- The offshore wind power parks of Borssele (1.4GW, commissioning planned in 2020) and Dunkirk (0.6GW, commissioning planned in 2026) are very close to the Belgian borders. Extreme events could pottentially hit those wind parks and the Belgian wind parks during a same period of time. This reinforces the need for each TSO to keep its system imbalance under control for 2 reasons. Firstly, the frequency quality of the synchronous area would otherwise be degraded by simultaneous events at several TSOs. Secondly, each TSO may not be able to count on the neighbour's (market) support when facing an extreme event.

For the wind parks to be commissioned between 2026 and 2028, the tendering phase for the wind farm concessions is planned in 2023. Figure 2 illustrates Elia's workplan with regard to contracts and system integration towards the tendering phase. The general objective of the System Integration stream of the MOG II project is to formulate recommandations to cope with the power variations that will result from an extended offshore wind capacity. As these recommandations could include operational or technical constraints for the wind parks or concerned BRPs, they must be clarified before the tendering process, as it will reduce uncertainties for the candidates and eventually reduce the cost for society.

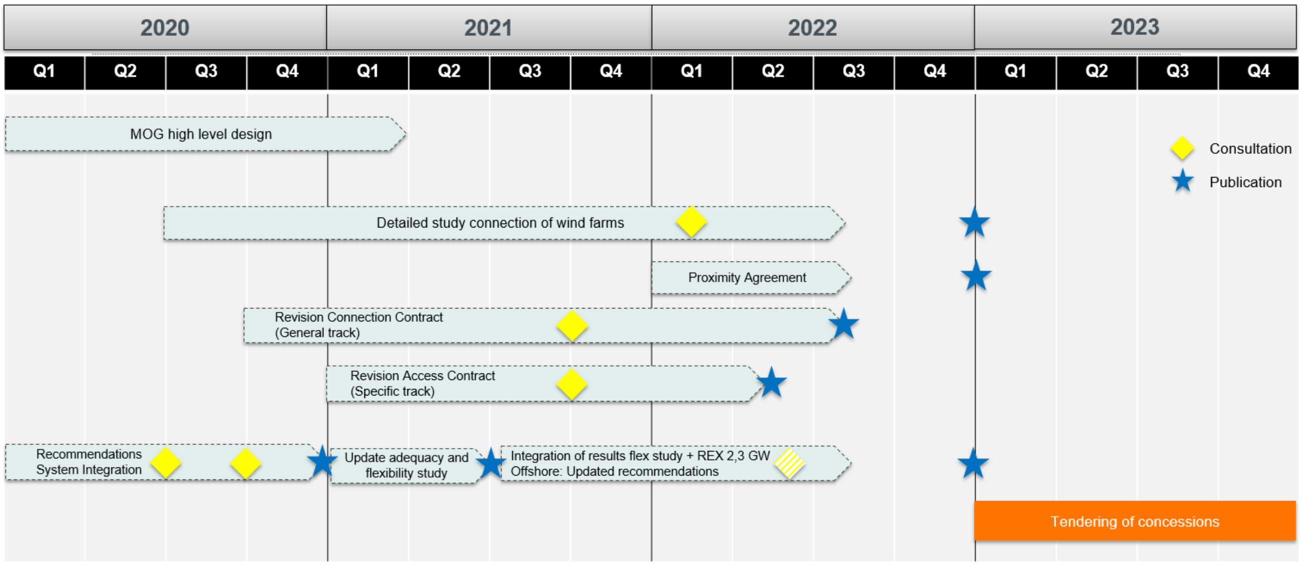


Figure 2: Elia's work plan towards tendering phase and the development of MOG II

The System Integration stream is organized in 2 phases:

- 2020: the present study aims at defining the impact of the extended capacity and formulate recommandations
- 2021-2022: during this period, assumptions used in the 2020 study will have to be verified and amended when needed. Assumptions will be verified a.o. on the basis of the updated adequacy and flexibility study and the return of experience of 2.3 GW installed capacity, together with the current "storm procedure" and the revised Alpha component of the imbalance price. Should the assumptions lead to a modification of the recommandations from the 2020 study, a new public consultation would be foreseen.

The content of the present study is the following:

- Evaluation of future offshore generation profiles, which are to be used as input for the upcoming analyses. This part of the study has been realized with the support of an external consultant (DTU). The full report of DTU is available in annex A of this report. The main results are described in **Section 2** of the present report.

- Determination of the impact on the system's flexibility needs. The methodology of the "Adequacy and Flexibility study 2020-2030"[5] published in 2019 has been used. This is described in **Section 3** of the present report.
- Determination of the impact on Elia's reserve needs. This analysis is based on the currently applied methodologies to determine Elia's FRR reserve capacity needs. This is described in **Section 4** of the present report.
- Determination of the impact on the real-time system operations. A dedicated model has been developed to evaluate the ACE on the basis of the offshore production profiles, assumptions on BRPs' ability to deal with large ramping and storm events and activation of Elia reserves. This is described in **Section 5** of the present report.
- Analyis of potential mitigation measures. At this stage of the study, a preliminary list of potential mitigation measures has been established and is explained in **Section 6**.

Two stakeholder workshops have been organized earlier this year. During the 1st workshop, the project has been presented and the assumptions used for the evaluation of future offshore generation profiles, in particular the technological developments, have been disucssed with the stakeholders. The 2nd workshop was focused on the results of the evaluation of future offshore generation profiles and the presentation of the methodologies to determine the impact on system's flexibility needs, Elia's reserve needs and real-time system operations.

The present public consultation is an opportunity to initiate or pursue discussions with stakeholders, in particular on the assumptions made for the analyses, on the methodologies used and on the preliminary list of mitigation measures. Based on this, an update of the impact analyses might be performed and the mitigation measures will be further developed. The results will be subject to a 2nd public consultation, planned on the 1st of October. The final report of the study will be delivered by the end of 2020.

[5] Available via https://www.elia.be/en/publications/studies-and-reports

2. Offshore generation profiles

2.1. Introduction

Considering the expected impact of additional offshore wind capacity on the grid, it is of particular importance to appropriately model the future offshore generation profiles, taking into account the geographical smoothening between the parks, as well as the wake effects within the parks and between the parks, including with the Borssele wind park in the Netherlands, located very close to the existing Belgian parks.

DTU has been selected to support Elia in this task. DTU has recognized expertise in wind power and has developed models for this purpose which are widely used.

As a first step of this task, Elia and DTU worked on the assumptions to be used for running the models. Scenarios were built with different offshore wind turbine technologies and installed capacities.

In a second step, DTU developed the methodology to simulate the generation profiles, including wake modeling and storm shutdown behavior. Then, the models were validated based on measurement data from Belgian wind parks until end of 2018.

As the model validation showed satisfying results, DTU simulated the time series and calculated statistics for analyzing future extreme events (rampings and storms) and forecast errors.

Finally, DTU provided some statistics on the system imbalances, the individual BRP's imbalances and the forecast errors based on data from the real system operation in 2018 and 2019. It's to be noted that, for confidentiality reasons, the statistics including BRP specific information can't be disclosed and have been removed from the public version of DTU's report in annex.

These different steps have already been extensively discussed with the stakeholders during the two workshops. The feedback received from the stakeholders has been taken into account in the analyses.

The statistical results presented in the full report in annex and summarized in this Section provide a general view on the impact of additional offshore wind capacity on the variation of wind power. For example: what is the expected frequency of ramping events above 2.0 GW in hour time in function of the assumptions on offshore wind turbine technologies and installed capacities.

Next to these statistical results, DTU supplied data that have been used for the analyses (see sections 3, 4 and 5), in particular:

- The simulated time series representing the 2018-2019 system conditions, which are used for the analyses of the impact on system flexibility needs and Elia's reserve needs. The method agreed on with DTU to generate these time series is explained in detail in section 5.4 of DTU's full report and summarized in Section 2.3 of the present report.
- A dataset with historic and simulated extreme events in the future, which is used for the analysis of the impact of extreme events on real-time system operation.

The link between the scenarios, the simulation of the generation profiles and the way those are used is illustrated in Figure 3.

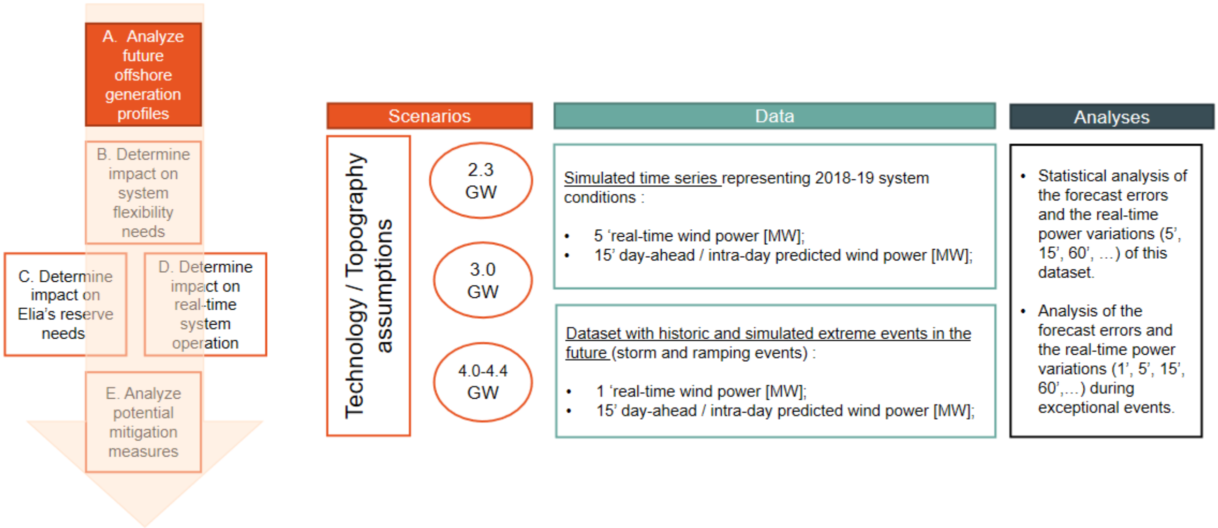


Figure 3: overview of the link between scenarios used, simulation of generation profiles and further use in the study

Upon request, Elia will supply at least the following time series to interested stakeholders:

- The sum of the production of all existing parks for the 37 years simulated, in 5 minutes resolution
- The sum of the production of all new parks for the 37 years simulated, in 5 minutes resolution

It is to be noted that the cases where the wind parks voluntarily decide to reduce production, like negative prices, self-curtailment or maintenance are not included in the analysis from DTU, nor in subsequent impact analyses. The production decrease resulting from those voluntary actions is expected to be lower than the ramping events resulting from wind variations, but it could potentially occur very fast. This is addressed in Section 6.

2.2. Scenarios

2.2.1. Assumptions related to offshore wind technologies

For the existing and planned 2.3 GW offshore capacity, the known data was used in the models and no assumptions had to be made.

Regarding the future, a limited number of scenarios were selected based on:

- Danish Energy Authority scenario (hub height, nominal power and specific power)
- Historical trends
- Public manufacturer specifications (focus on storm protection)
- Manufacturer consultations (storm protection, hub height, nominal power and specific power, yaw correction)

This exercise resulted in the definition of 2 technologies A and B, the most relevant characteristics of which are listed in Table 1. Both technologies assume a same rated power, but the expected impact of this assumption on the purpose of this study is limited.

Table 1: Technology scenarios for offshore wind turbines for additional installations

Technology scenario	A	B
Rated power	12 MW	12 MW
Rotor diameter	184 m	220 m
Hub height	118 m	150 m
Specific power	450 W/m^2	316 W/m^2

Those assumptions lead to the generic power curves shown in Figure 4 for the two technology scenarios, Tech A and Tech B. On top of this, based on manufacturer brochures and literature review, three high wind technology scenarios also shown in Figure 4 have been considered:

- For **25 direct cut-off**, which is considered as baseline, the wind turbine will shut down when the 10 minute average wind speed exceeds 25 m/s.
- For **HWS Moderate**, the power will reduce for increasing wind speeds until the wind turbine shuts down at 28 m/s.
- Finally for **HWS Deep**, the power will reduce for increasing wind speeds until the wind turbine shuts down at 31 m/s

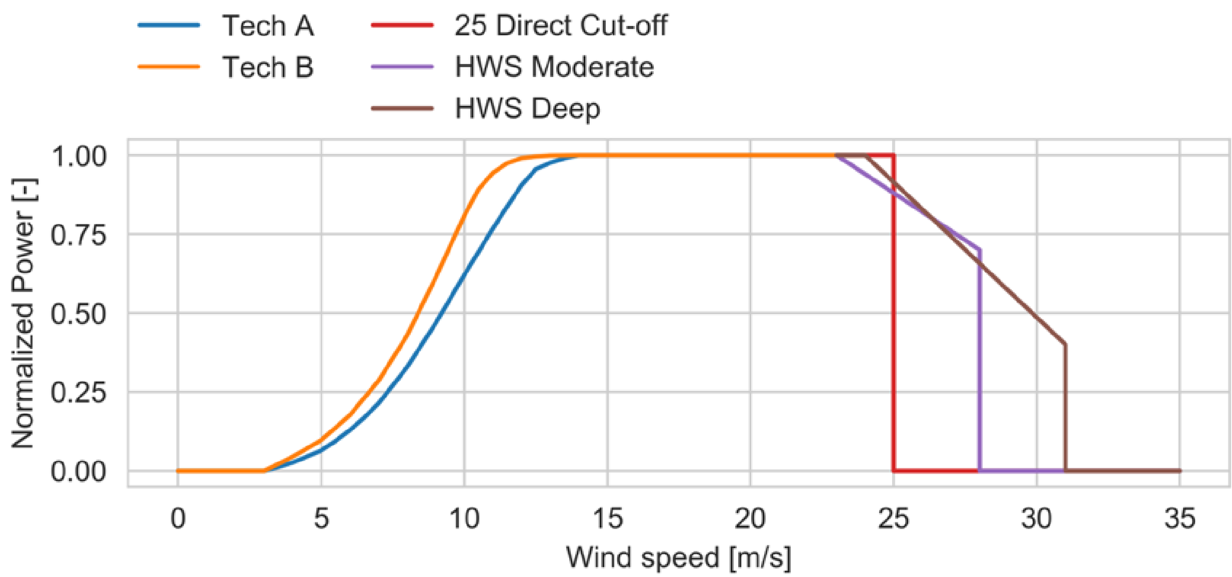


Figure 4: Power curves for assumed technology scenarios and storm shutdown scenarios

2.2.2. Assumptions on installed capacity

The several stages of the installations of the Belgium offshore wind power fleet considered in the present study are shown in Figure 5. The BE 2.3 GW stage consists of the fleet planned by end of 2020 (this includes the parks in BE2018 as well as Norther, Northwester 2, Rentel, Seastar and Mermaid).

The BE 4.4 GW scenario consists of the estimated locations of the future MOG II parks: this scenario includes the parks in the BE 2.3 GW as well as Noordhinder Noord (~700 MW), Noordhinder Zuid (~550 MW) and Fairybank (~850 MW). Two additional installation scenarios are modelled. In BE 3.0 GW, only Noordhinder Noord is considered in addition to the existing 2.3 GW. In BE 4.0 GW, all of the wind parks belonging to 4.4 GW are considered; however, they are all considered to have lower installed capacities.

The Borssele offshore cluster in the Netherlands is considered because large wake effects are expected due to its proximity to the Belgian fleet.

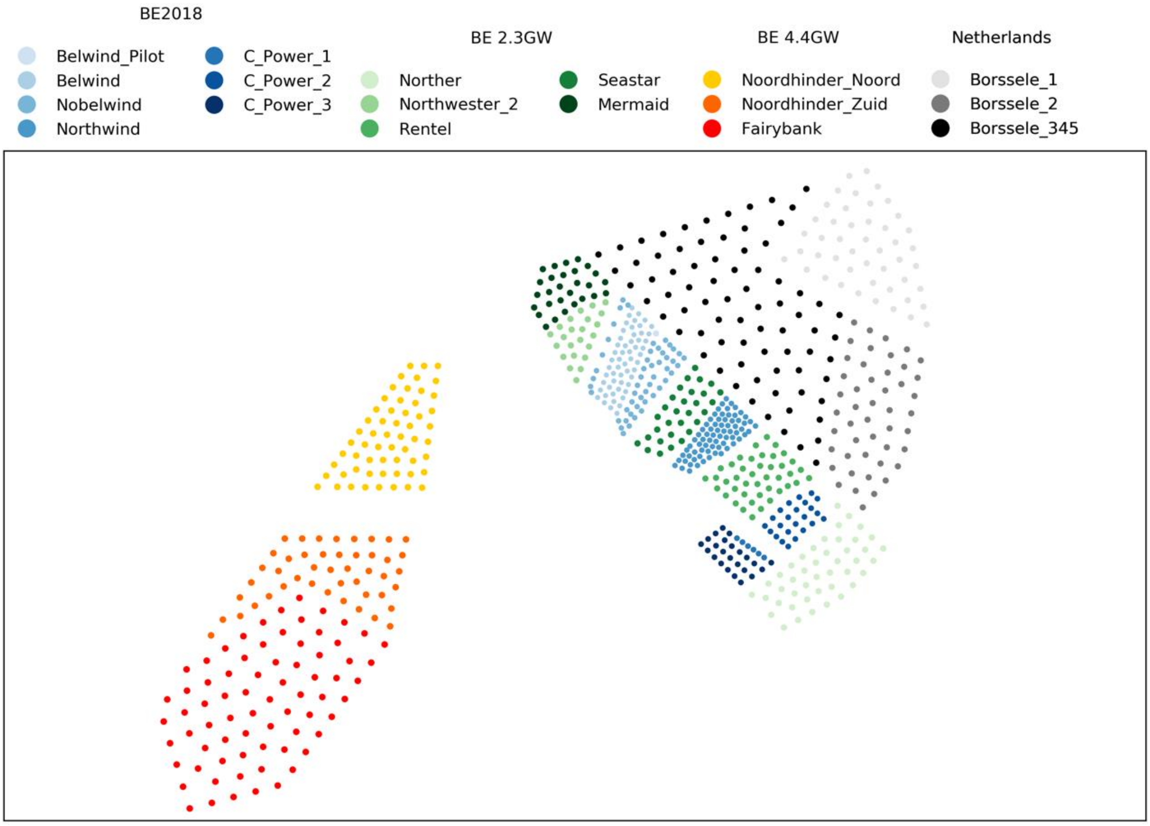


Figure 5: Park and turbine locations for the different stages of offshore wind installations. The Dutch parks are taken into account when modelling external wake impacts on the Belgian wind parks.

2.2.3. The scenarios

For the installation scenarios described in the previous section, different turbine technologies are modelled. The resulting scenarios, considering the different amounts of installations and different technologies, are listed in Table 2. Going from BE2018, which is used for model validation, the installed capacity increases towards 4.4 GW. All of the scenarios with 3.0 GW or more installed have the same 2.3 GW as the currently planned installations with fixed technology; then, different amounts of additional installations with different technologies are added to the existing fleet to reach the total installed capacity of the scenario.

Table 2: The studied scenarios

Name	Installed capacity (MW)	Tech type	Storm shutdown type
BE 2018	877	Known existing data	Known existing data
BE 2.3 GW	2300	Known existing data	Known existing data
BE 3.0 GW	2300 existing + 700 additional	Tech A	25 m/s
			Moderate
			Deep
		Tech B	25 m/s
			Moderate
			Deep
BE 4.0 GW	2300 existing + 1700 additional (Noordhinder Noord, Noordhinder Zuid and Fairybank; all with lower installed capacity)	Tech A	25 m/s
			Moderate
			Deep
		Tech B	25 m/s
			Moderate
			Deep
BE 4.4 GW	2300 existing + 2100 additional (Noordhinder Noord, Noordhinder Zuid and Fairybank)	Tech A	25 m/s
			Moderate
			Deep
		Tech B	25 m/s
			Moderate
			Deep
		Tech A/B	25 m/s
			Moderate
			Deep

Notes related to Table 2:

- For BE 3.0 GW, BE 4.0 GW and BE 4.4 GW, the tech type and storm shutdown type are for the additional installed capacity; the planned 2.3 GW has technology specified based on known existing data.
- The Tech A/B type for BE 4.4 GW has a mixture of Tech A and Tech B installations: Noordhinder Noord (~700 MW) has Tech A and Noordhinder Zuid (~550 MW) and Fairybank (~850 MW) have Tech B.

2.3. Methodology

Section 5 of the DTU report presents in detail the modelling methodology used in the MOG II analyses.

2.3.1. Corwind and wake modeling

The flowchart of the modeling, from the definition of the scenarios, to the CorWind tool developed and used by DTU for simulating the time series and finally the wake modelling for including wake impacts in the CorWind simulations, is illustrated in the flowchart of Figure 6.

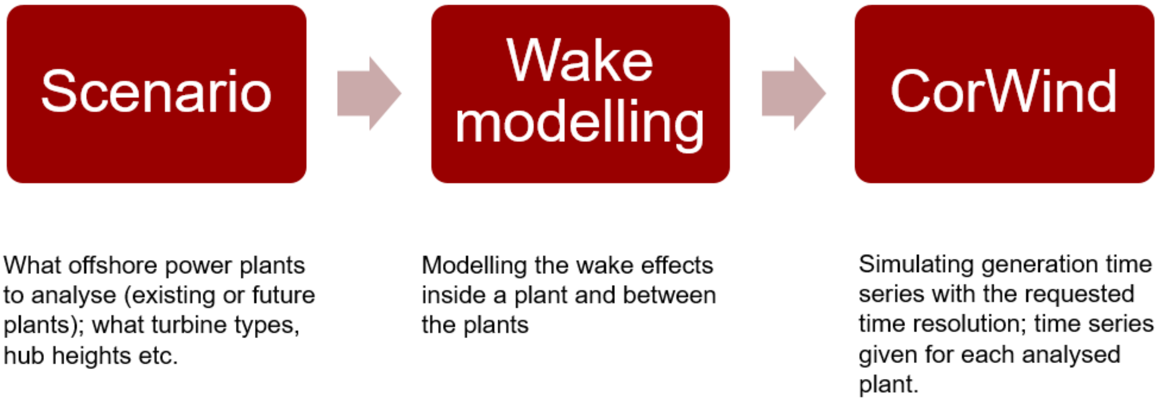


Figure 6: flow chart of the modeling

DTU's report explains among others how the 37 years of meteorological data (1982-2018) produced by the WRF (Weather Research and Forecasting) are used for the simulations and how intra-hour fluctuations are captured, which was essential for the purpose of this study.

2.3.2. Storm shutdown behavior

When simulating multiple years of generation time series with CorWind on 5 min resolution for multiple wind parks, the simulations need to be done on park-level; simulation of individual turbines is not feasible for such long time series. However, as the storm shutdown behaviors are given on turbine-level (Figure 4), the behaviors of the different shutdown technologies need to be modelled on park-level. This leads to Park-level hysteresis modelling, as detailed in section 5.3 of DTU's report.

2.3.3. Data for the analysis of the system's flexibility needs (section 3) and Elia's reserve capacity needs (section 4)

Results presented in DTU's report are based on simulated data from CorWind. These simulations relate to meteorological data from 1982 to 2018. However, the meteorological data cannot be taken to represent the reality exactly on 5 min or even hourly resolution: even though the high and low wind events happen approximately at the same times in the meteorological data and as in reality (measured data), e.g., the exact time when a wind variation affects a wind park in the simulation is not the same as in reality. In addition, the stochastic simulations in CorWind, which add the intra-hour variability to the data to better represent the wind variations, do not add those variations exactly at the same times as in measured data. For these reasons, the results from CorWind are assessed statistically; e.g., how many days in a year on average a significant ramping event is expected to occur.

However, in order to evaluate the impact of incremental offshore wind power capacity on the assessment of the flexibility needs and the dimensioning of reserve capacity, Elia combines offshore wind power generation and forecast time series with similar time series from other drivers for flexibility needs or reserve capacity needs (e.g. onshore wind and solar generation). Where offshore generation and forecast time series used to result from upscaling Elia's historic observations, similar to the other renewable generation technologies, DTU has created time series which represent the geographical smoothing effects of the different turbines for a 2.3 GW, 3.0 GW, 4.0 GW and 4.4 GW scenario, as well as representing the impact of the technology scenarios.

The different step of process to provide representative generation time series for the future scenarios based on measured time series are the following:

- The voluntary control actions from the wind parks are removed
- The measurement data is aggregated to 5 minute data. The reason is that the main variations are expected to be captured with this granularity. In other words, 1 minute granularity will have given very similar end results. In addition, 1 minute data would have required too much processing from the tool.
- A transformation is applied to represent the statistics with additional offshore capacity, taking into account the capacity factor of the assumed technologies of the future wind parks
- Finally, a filter is applied to capture the impact of geographical smoothening on reducing the standardized generation ramp rates

The forecasts measured from 2018 and 2019 are also processed to represent the expected reduction in fleet-level forecast errors. This is achieved by using the expected reductions in forecast error standard deviations before applying the filters described above.

Section 5.4 of DTU's report explains the process in detail and shows how the filters are calibrated.

Finally, for the data supplied with a 15 minute granularity, the 15 minute values are the average of the corresponding 5 minute values.

2.4. Model validation

2.4.1. Introduction

This Section presents the measured data from Elia used in CorWind model validation, and the validation results. Validation considers basic statistics, such as capacity factors (CFs) and standard deviations (SDs), and probability density functions (PDFs). Ramp rates and behavior during storms are also validated. The validation is performed on park level as well as on aggregated level. The last paragraph of this Section looks also at the simulation of forecasts, and resulting forecast errors.

For DTU to perform the model validation, following data was supplied:

- The measured generation data from the following wind parks on 15 min resolution are used for model validation: Nobelwind, Belwind, Northwind, C_Power_1, C_Power_2 and C_power_3. The data from 2015 to 2018 are used as the main validation dataset.
- Day-ahead, intraday and the latest ("Last") forecast errors on 15 min resolution for each wind park.
- Wind generation data on 1 min resolution for 2018.
- Wind speed data from Nobelwind, Belwind and Northwind and from C_Power. For C_power. Wind speed data are available from 4 turbines per measurement location.

It's to be noted that the data produced by the WRF are available from 1982 until the end of 2018. Therefore, measured data newer than 2018 cannot be used in validation.

2.4.2. Results of the model validation

The model validation shows that CorWind is able to model the generation time series of the existing offshore wind power parks in Belgium (the BE2018 wind parks). It is thus considered valid for modelling the MOG II capacity extension.

The capacity factors predicted by CorWind are slightly larger than the measured data because the simulations assume 100 % availability of the turbines. However, availability could not be applied as a static factor (e.g., 0.95), because it would change other statistics that are well modelled (e.g., SD). In addition:

- Full installed capacity ramps are seen in data during a few hours;
- The availability factor in the future is unknown, also but not only for the additional installations;
- Overplanting is not to be excluded for the additional installations.

Therefore, it would not be appropriate to include an availability factor for the purposes of this study, nor to post-process the results which would artificially decrease the evaluation of extreme events.

Statistics of ramping events are similar for the measured and simulated data. There is a slight underestimation of the 0.1 and 99.9 percentiles, as shown in the example of 1 hour ramping events in Table 3. This means that the likelihoods of the events rarer than the 0.1 and 99.9 percentile range may be underestimated in CorWind. However, the simulated data are not adjusted, because the reason for these differences cannot be clearly identified. This needs to be noted when assessing the results of the extended capacity simulations.

Table 3: 1 h ramping event statistics of the aggregate offshore wind generation (Prct = percentile)

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	0.000	0.087	-0.843	-0.495	-0.255	-0.131	0.135	0.270	0.511	0.892
CorWind	0.000	0.089	-0.872	-0.432	-0.249	-0.143	0.148	0.257	0.429	0.870

The highest wind speed from the mesoscale WRF data are increased by 8 %. This is justified looking at the measured wind speed data, and based on literature on the expected underestimation of maximum wind speeds in WRF. The resulting CorWind runs model well the likelihoods of very high wind speeds. The use of 37 years of meteorological data in the simulation of the extended capacity ensures that a wide range of extreme events are simulated.

For forecast errors, CorWind shows similar statistics compared to measured data. The SDs differ slightly for day-head and intraday; however, percentiles and min and max values are similar. For the “Last” forecast errors, CorWind shows somewhat lower general uncertainty than the measured data; however, min and max values are similar to measurements. In general, forecast errors are more difficult to simulate, as the target is not to replicate the variability due to weather, but to try to represent the forecasts by the Elia’s forecast provider. For this reason, the results presented for forecasts and forecast errors for the extended capacity scenarios need to be taken as indicative changes resulting from different geographical installation distributions and storm shutdown technologies. The actual simulated forecast and forecast error values for an individual event are stochastic, and can be high or low due to randomness.

2.5. Expected ramping events

2.5.1. Introduction

This Section presents the results on ramping events for the studied scenarios. 37 years, from 1982 to 2018, are simulated on 5 min resolution. Each wind parks is simulated, although only aggregated ramp results are reported. All results are given based on 5 min resolution data.

The first section compares the scenarios in standardized generation, as the impact of geographical smoothening is easier to see when all data are standardized. The second section shows results in GW, as it allows to visualize the impact for the grid.

It is to be noted that the storm events are not filtered out of the data, which means that the ramping events that occur during the cut-out and the cut-in phases of storms are included in the statistics presented. However:

- In order to isolate the ramping events which are not due to storms, section 8.4 of DTU’s report shows the same results but only for those days when the maximum daily wind speeds is below 20 m/s.
- The time series delivered by DTU to Elia in addition to the statistics were used to evaluate the impact on real-time system operations for specific events, allowing to make a clear distinction between ramping and storm events.

The present report focuses on the 1 hour ramping events, as those are expected to have the most significant impact on real-time system operation. DTU’s report also includes the results for 5 and 15 minutes ramping events.

2.5.2. Results for 1 hour ramping events expressed in standardized generation

Figure 7 shows the 1 h ramping event PDFs for some example scenarios. It can be seen that the 1 h ramping events expressed in standardized generation decrease from BE 2018 towards the 4.4 GW of installations (although to a lesser extent than for the 5 min and 15 min ramping events presented in DTU’s report). The PDFs of the different storm shutdown types show very similar PDFs for the 4.4 GW scenario.

1h ramping event statistics of all scenarios are shown in Table 4. The ramping event SD decreases significantly from BE 2018 towards the 4.4 GW scenarios. Tech A and B show similar ramping event statistics; however, ramping events in the Tech B scenarios are slightly higher. Unlike for the 5 and 15 min ramping events, the Deep and Moderate storm shutdown types show only marginally decreased likelihoods for the most extreme ramping events compared to the 25 direct cut-off. It can be seen that the ramping event distributions tend to be skewed slightly to the right; this means that there are more extreme upwards than downwards ramping events.

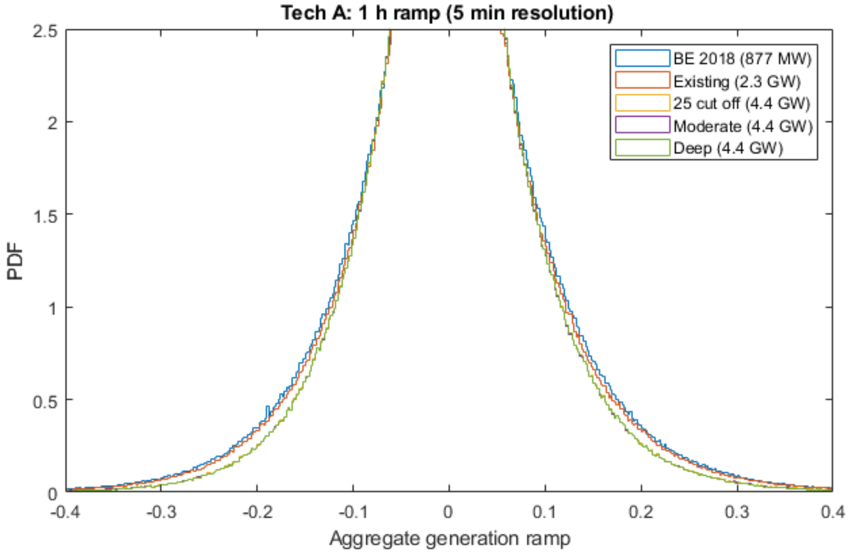


Figure 7: 1h ramping event PDFs for example scenarios (standardized generation). The 4.4 GW scenarios with different storm shutdown types are almost fully on top of each other.

Table 4: 1 h ramping event (5 min resolution) statistics (standardized generation).

								Compared to BE 2018		
			SD	**Prct 0.01**	**Prct 0.1**	**Prct 99.9**	**Prct 99.99**	**SD**	**Prct 0.1**	**Prct 99.9**
BE 2018 (877 MW)			0.092	-0.604	-0.425	0.463	0.732	100%	100%	100%
Existing (2.3 GW)			0.088	-0.561	-0.395	0.434	0.629	96%	93%	94%
3.0 GW	**Tech A**	**25 m/s**	0.084	-0.522	-0.370	0.411	0.597	91%	87%	89%
		Moderate	0.083	-0.522	-0.370	0.409	0.596	91%	87%	88%
		Deep	0.083	-0.522	-0.367	0.407	0.592	90%	86%	88%
	Tech B	**25 m/s**	0.083	-0.531	-0.371	0.404	0.579	91%	87%	87%
		Moderate	0.083	-0.528	-0.372	0.404	0.580	90%	88%	87%
		Deep	0.083	-0.527	-0.371	0.401	0.578	90%	87%	87%
4.0 GW	**Tech A**	**25 m/s**	0.079	-0.520	-0.362	0.391	0.583	86%	85%	84%
		Moderate	0.078	-0.504	-0.350	0.382	0.572	85%	82%	83%
		Deep	0.078	-0.488	-0.342	0.374	0.543	85%	81%	81%
	Tech B	**25 m/s**	0.080	-0.516	-0.372	0.390	0.570	86%	88%	84%
		Moderate	0.079	-0.508	-0.360	0.379	0.563	85%	85%	82%
		Deep	0.078	-0.500	-0.352	0.371	0.549	85%	83%	80%
4.4 GW	**Tech A**	**25 m/s**	0.079	-0.541	-0.366	0.393	0.600	86%	86%	85%
		Moderate	0.078	-0.511	-0.351	0.383	0.577	85%	83%	83%
		Deep	0.078	-0.489	-0.343	0.375	0.544	85%	81%	81%
	Tech B	**25 m/s**	0.080	-0.537	-0.380	0.397	0.588	87%	89%	86%
		Moderate	0.079	-0.521	-0.363	0.382	0.576	86%	86%	83%
		Deep	0.078	-0.503	-0.354	0.374	0.553	85%	83%	81%
	Tech A/B	**25 m/s**	0.079	-0.537	-0.370	0.388	0.589	86%	87%	84%
		Moderate	0.078	-0.511	-0.357	0.377	0.570	85%	84%	81%
		Deep	0.078	-0.493	-0.350	0.368	0.547	85%	82%	80%

The ramp rate distributions for the Tech A/B scenario for the BE 4.4 GW showed results in between the fully Tech A and fully Tech B scenarios. Thus, it was considered that analyzing such mixed technology scenario does not provide any additional insight compared to analyzing only the 100% Tech A and 100 % Tech B scenarios. The Tech A/B scenario is not included in the results presented in next section.

2.5.3. Results for 1 hour ramping events expressed in GW

This section describes the ramp rate results in GW. The simulated data are the same as in the previous section.

Table 5 shows the average number of days per year with at least one ramping event more extreme than the given GW value for 1 h ramping events (on 5 min resolution), excluding the storm events from the data (this is done by filtering out the days where the maximum fleet-level wind speed is higher than 20m/s). The differences between the scenarios are the same as discussed in previous section, but here the scenarios with more installed GW of course show more extreme ramping events. The tendency of the ramp PDF to be skewed slightly to the right shows a higher number of events, for example more 2 GW upward ramping events than 2 GW downward ramping events. This is mostly explained by the cut-in phase of storm events.

Table 5: 1 h ramping events: average number of days per year with at least one event more extreme than the limit when the daily max fleet-level wind speed is below 20 m/s

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)										2.8	49.9	56.1	4.6							
Existing (2.3 GW)							0.1	0.5	11.2	163.9	266.4	265.3	168.7	16.1	1.1	0.1				
3.0 GW	Tech A	25 m/s				0.0	0.3	2.6	28.4	212.1	285.2	282.2	215.1	38.4	4.8	0.5	0.1			
		Moderate				0.0	0.3	2.6	28.4	212.1	285.2	282.2	215.0	38.4	4.8	0.5	0.1			
		Deep				0.0	0.3	2.6	28.4	212.1	285.2	282.2	215.0	38.4	4.8	0.5	0.1			
	Tech B	25 m/s				0.1	0.3	2.7	29.3	214.2	286.5	283.6	215.8	37.3	4.3	0.5	0.1			
		Moderate				0.1	0.3	2.7	29.3	214.1	286.5	283.6	215.6	37.3	4.3	0.5	0.1			
		Deep				0.1	0.3	2.7	29.3	214.1	286.5	283.6	215.6	37.3	4.3	0.5	0.1			
4.0 GW	Tech A	25 m/s			0.1	0.3	1.5	9.1	67.2	248.2	299.0	295.9	248.5	79.4	14.1	2.6	0.5	0.1	0.0	
		Moderate			0.1	0.3	1.5	9.1	67.2	248.1	299.0	295.9	248.4	79.4	14.1	2.6	0.5	0.1	0.0	
		Deep			0.1	0.3	1.5	9.1	67.2	248.1	299.0	295.9	248.4	79.4	14.1	2.6	0.5	0.1	0.0	
	Tech B	25 m/s			0.1	0.4	1.9	11.4	70.9	251.0	299.9	298.0	251.6	77.5	13.8	2.3	0.3	0.0	0.0	
		Moderate			0.1	0.4	1.9	11.4	70.9	250.9	299.9	297.9	251.5	77.4	13.7	2.2	0.3	0.0	0.0	
		Deep			0.1	0.4	1.9	11.4	70.9	250.9	299.9	297.9	251.5	77.4	13.7	2.2	0.3	0.0	0.0	
4.4 GW	Tech A	25 m/s			0.1	0.6	2.9	15.8	93.3	262.2	304.1	301.5	261.1	104.1	22.6	4.6	1.1	0.1	0.0	0.0
		Moderate			0.1	0.6	2.9	15.8	93.2	262.2	304.1	301.5	261.1	104.1	22.5	4.6	1.1	0.1	0.0	0.0
		Deep			0.1	0.6	2.9	15.8	93.2	262.2	304.1	301.5	261.1	104.1	22.5	4.6	1.1	0.1	0.0	0.0
	Tech B	25 m/s			0.1	0.7	3.4	19.1	100.2	264.4	304.5	303.1	265.2	106.3	23.4	4.2	0.8	0.2	0.0	0.0
		Moderate			0.1	0.7	3.4	19.1	100.1	264.3	304.5	303.0	265.1	106.2	23.2	4.2	0.8	0.2	0.0	0.0
		Deep			0.1	0.7	3.4	19.1	100.1	264.3	304.5	303.0	265.1	106.2	23.2	4.2	0.8	0.2	0.0	0.0

2.5.4. Conclusions

Considering standardized generation, ramping events are expected to be reduced towards the 4.4 GW of installations. This is caused by geographical smoothening. 5 min ramping events are reduced more than 1 h ramping events. However, when expressed in GW, ramping events are expected to increase significantly in the future. Extreme upward ramping events are more likely than similar size downward ramping events.

For days without high wind speed (> 20 m/s), an upward ramping events larger than 4.0 GW within 1 hour (5 min resolution) was seen once in the simulation for the 4.4 GW scenarios. This shows that extreme ramping events are possible also on non-storm days, but they are unlikely. Even though similar sizes downward ramping events was not seen in the simulations, it cannot be ruled out that such downward ramping events could happen in the future.

Next to these most extreme events, the results for 4.4 GW installed capacity show that ramping events of more than 2GW in 1 hour time are to be expected about 7 times a year and ramping events of 2.5GW about 1 to 2 times a year, on average. These values exclude ramping events during high wind speed days.

2.6. Expected storm events

2.6.1. Introduction

This Section presents statistics of storm events in the simulated 37 years of data. Both the likelihoods of fleet-wide shutdowns and ramping during high wind speed days are reported. All results are given based on 5 min resolution data.

Simulated fleet-level wind speeds for the BE 4.4 GW Tech A scenario can be seen in Figure 8. The highest fleet-level wind speeds reach approximately 35 m/s (5 min resolution); highest park-level wind speeds are even higher. It can be observed that high wind speeds occur throughout the 37 years; however, the latest few years up to 2018 do not show very high wind speed peaks, meaning that the most extreme weather conditions have not yet been experienced by the offshore wind parks. Tech B shows slightly higher fleet-level wind speeds due to additional installations having higher hub heights.

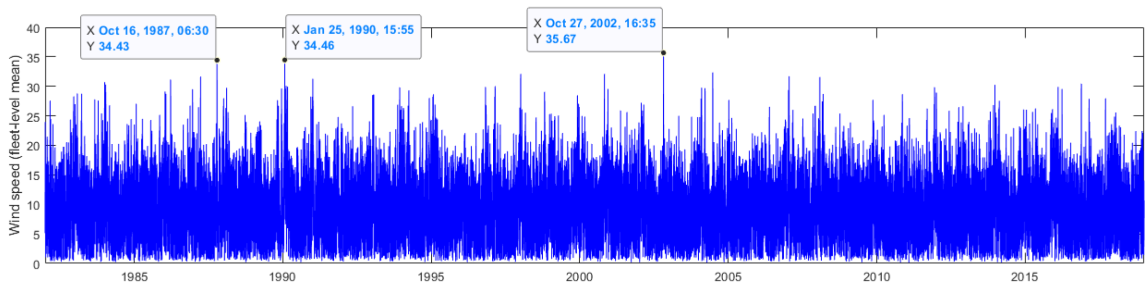


Figure 8: Effective fleet-level wind speeds (weighted by installed capacity of the wind parks) in the BE 4.4 GW Tech A scenario (5 min resolution). Time series are until the end of 2018; some of the highest peaks are marked.

2.6.2. Generation during storms

Example time series around the 1990 extreme high wind speed event (as seen in Figure 8) can be seen in Figure 9. With such high wind speeds, the entire fleet (4.4 GW) is in shutdown for some hours with all the scenarios considered. In this specific example, the Moderate and Deep types show smoother ramping than the 25 direct cut-off; however, on the aggregate 4.4 GW level (top subplot), they all reach zero generation at the same time. Existing installations show smooth shutdown behavior, because some wind parks have a higher than 25 m/s cut-off limit and many wind parks have the Deep shutdown behavior also in the existing installations (middle subplot). The existing installations shut down later than the Deep additional installations because wind speeds in the existing locations increase later and up to a lower maximum level than in the additional locations (bottom subplot).

Figure 10 shows that even with the Deep shutdown type, the 4.4 GW Tech A scenario is expected to sometimes experience a full shut-down. Figure 11 shows that the storm shut down type does not have a significant impact on the number of occurrences where the entire fleet experiences a total shut-down; although the Deep types shows slightly less shut-down hours. These observations are in line with the case plotted in Figure 9. However, Figure 9 also suggests that there are differences in ramping during storm events for the different shutdown types; this is investigated in the following sections.

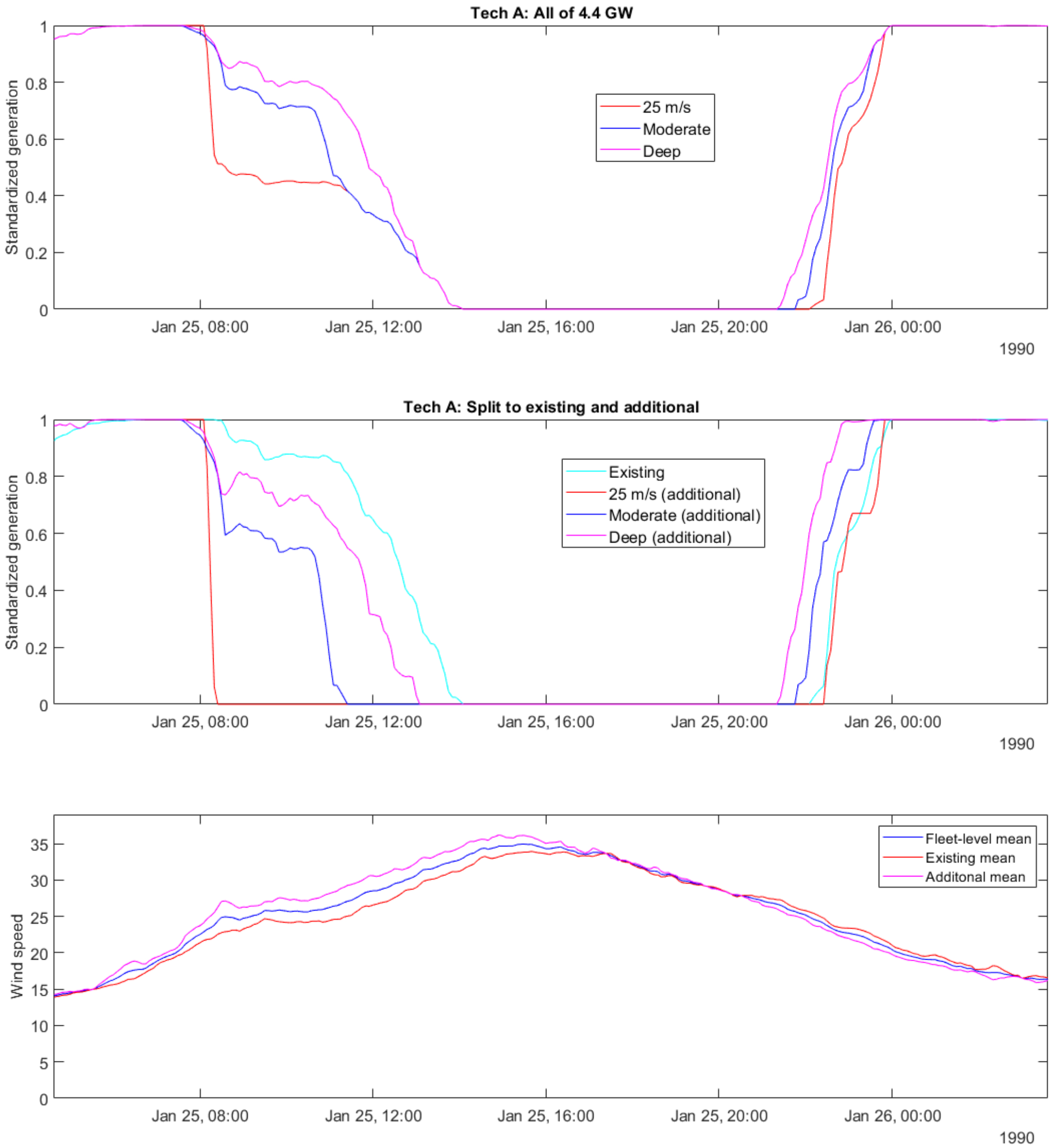


Figure 9: Example extreme storm case for the BE 4.4 GW Tech A scenario: all storm shutdown types plotted. Subplots show also split to existing (2.3 GW) and additional installations (2.1 GW) and effective wind speeds (for entire fleet and existing and additional parts).

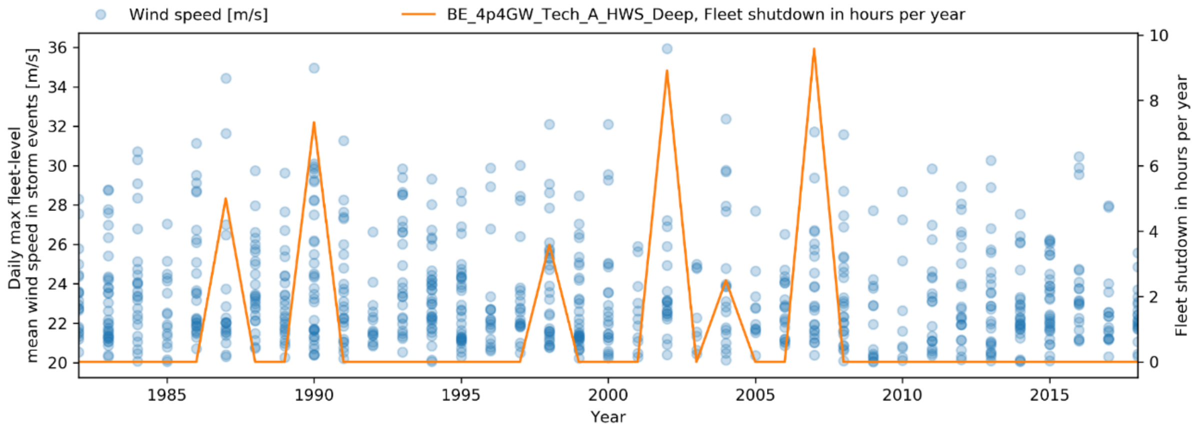


Figure 10: Number of hours when the entire fleet is in shutdown (aggregate generation zero) per year for the BE 4.4 GW Tech A Deep storm shutdown scenario.

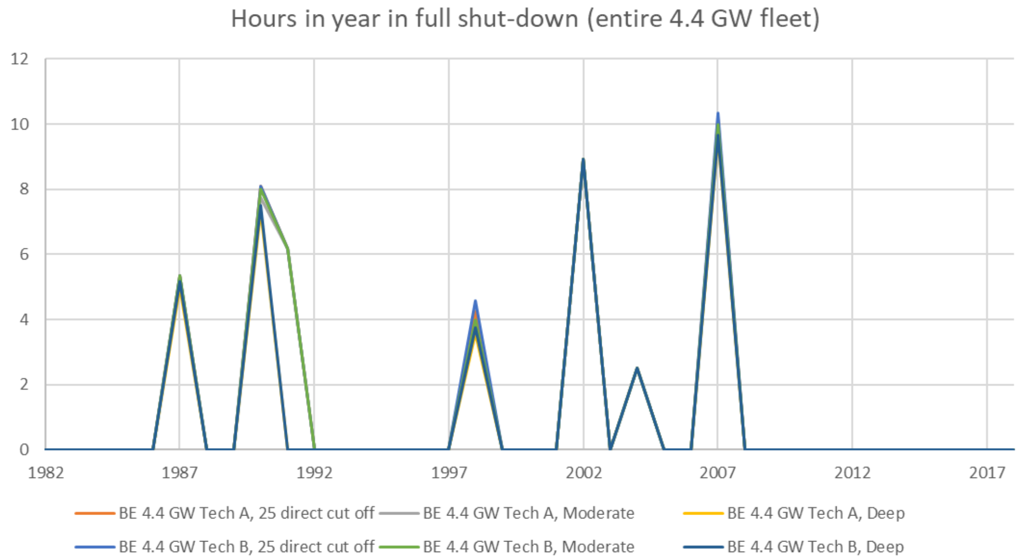


Figure 11: Number of hours when the entire fleet is in shut-down (aggregate generation zero) per year for the 4.4 GW scenarios. Full shut-down occurs in 6 or 7 of the 37 simulated years.

2.6.3. Ramping events during high wind speed days

Table 6 shows the average number of days per year with at least one ramping event more extreme than the given GW limit for 1 h ramping events for those days when the daily max wind speed is above 20 m/s. It shows that the Deep type has reduced likelihoods for negative ramping events over 2 GW compared to 25 direct cut-off for the 4.0 and 4.4 GW scenarios, but even the Deep type can experience very high negative ramping events (3 GW or more), and the Moderate type for BE 4.4 GW Tech B actually shows higher extreme down-ramp than the 25 direct cut-off scenario. This is further justified in DTU's report.

Table 6: 1 h ramps: average number of days per year with at least one event more extreme than the limit for days with max fleet-level wind speed above 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	**3.5**	**3.0**	**2.5**	**2.0**	**1.5**	**1.0**	**0.5**	**0.3**	**0.3**	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**
BE 2018 (877 MW)										1.4	7.3	9.2	2.9							
Existing (2.3 GW)							0.0	0.3	1.7	12.6	20.1	20.5	14.0	2.8	0.6	0.1				
3.0 GW	**Tech A**	**25 m/s**				0.0	0.1	0.6	5.0	17.8	22.8	23.3	18.8	6.9	1.8	0.5	0.2			
		Moderate				0.1	0.1	0.6	4.3	15.7	21.7	21.9	17.0	6.4	1.7	0.5	0.2			
		Deep				0.1	0.1	0.5	3.6	15.3	21.6	21.8	16.5	5.3	1.5	0.4	0.1			
	Tech B	**25 m/s**				0.0	0.1	0.8	4.8	19.1	24.2	24.8	20.3	6.8	1.5	0.4	0.1			
		Moderate				0.0	0.1	0.6	4.5	16.1	22.1	22.7	17.7	6.4	1.5	0.5	0.1			
		Deep				0.1	0.1	0.6	3.8	15.5	22.0	22.4	16.9	5.5	1.4	0.4	0.2			
4.0 GW	**Tech A**	**25 m/s**				0.1	1.5	4.8	10.3	19.4	23.4	23.6	20.5	12.2	6.0	2.4	0.7	0.2	0.1	
		Moderate			0.0	0.1	0.8	2.7	7.6	17.1	21.9	22.1	18.1	9.6	4.2	1.6	0.7	0.2	0.1	
		Deep			0.0	0.1	0.3	1.6	6.6	16.6	21.8	21.8	17.9	8.2	3.1	0.8	0.3	0.1	0.1	
	Tech B	**25 m/s**				0.1	1.4	5.8	12.1	21.3	25.4	25.9	22.0	13.4	6.6	2.2	0.7	0.2	0.1	
		Moderate			0.0	0.1	0.8	3.4	8.0	17.5	23.0	23.8	18.5	9.7	4.0	1.8	0.6	0.3	0.1	
		Deep			0.0	0.1	0.3	1.9	6.6	16.9	22.8	23.4	17.8	8.2	2.7	1.1	0.5	0.2	0.1	
4.4 GW	**Tech A**	**25 m/s**			0.1	1.0	3.4	6.1	12.1	20.7	23.9	24.2	21.5	14.1	7.8	4.0	1.9	0.5	0.2	0.1
		Moderate			0.1	0.3	1.5	3.8	9.1	18.2	22.5	22.7	19.2	11.4	5.5	2.5	1.1	0.5	0.2	0.1
		Deep			0.0	0.2	0.6	2.3	8.2	17.9	22.4	22.5	18.8	10.1	4.1	1.4	0.5	0.2	0.1	0.1
	Tech B	**25 m/s**			0.1	0.6	4.0	7.6	14.0	22.3	26.4	26.6	23.2	15.4	8.8	4.6	1.6	0.5	0.2	0.1
		Moderate		0.0	0.1	0.3	1.7	4.5	9.6	18.7	24.0	24.5	19.7	11.4	5.5	2.7	1.4	0.5	0.2	0.1
		Deep			0.1	0.2	0.7	2.9	8.2	18.1	23.9	24.4	19.1	9.9	3.9	1.5	0.8	0.4	0.2	0.1

Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days (small differences between the scenarios).

2.6.4. Cut-in phase after storm events

From the section above, it can be seen that upwards ramping events are more likely than downward ramping events of the same magnitude for high wind speed days. For Moderate and Deep types, this is impacted by the storm shutdown types only affecting the shutdown and not the restart operation during storm. An example of this is shown in Figure 43: all the shutdown types experience a very fast 15 min upwards ramping events. In this case, the Deep and Moderate types show even larger 15 min upwards ramping events than the 25 direct cut-off type.

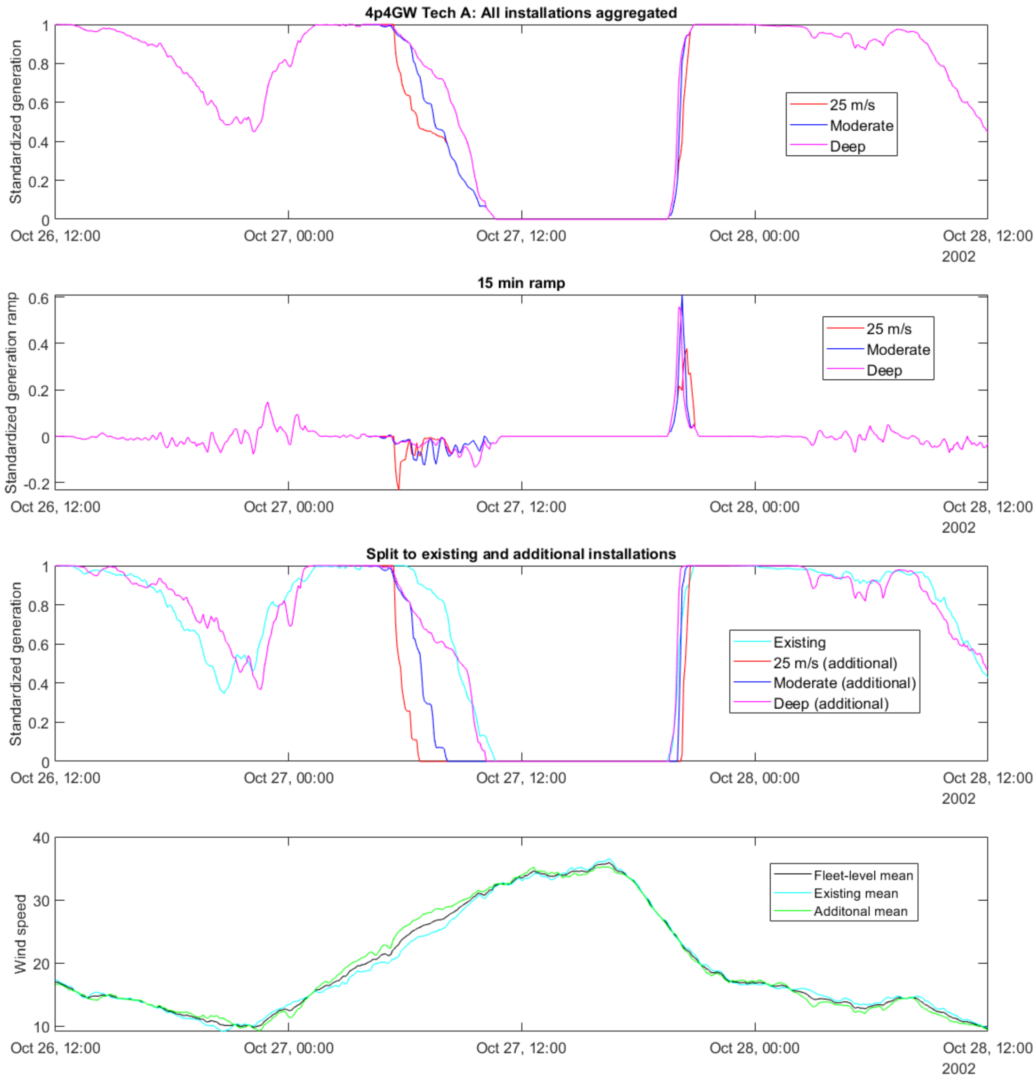


Figure 12: Example storm case for BE 4.4 GW Tech A, where the restart after the storm causes an extreme 15 min upwards ramping events, especially for the Moderate and the Deep types.

2.6.5. Conclusions

It is possible to lose the full 4.4 GW of installed capacity in all studied scenarios due to an extreme storm event. The number of years where this occurs is 6 or 7 out of the simulated 37 years for the 4.4 GW scenarios, depending on the technology scenario.

Storm shutdown type impacts the most extreme fast ramps by slowing down the down-ramps during storms. 5 and 15 min extreme down ramps are reduced significantly when comparing Deep to the 25 direct cut-off type. For example, for 15 min ramping events in the 4.4 GW scenarios, negative 2 GW down-ramp was seen in the simulations a few times over the 37 years for the 25 direct cut-off types, but such event was not seen for scenarios with the Deep storm type.

For 1 hour ramps in the 4.4 GW scenarios on high wind speed days, a down-ramp event of more than 2 GW is expected to happen on a few days over a year with the 25 direct cut-off type. For similar scenarios with the Deep storm shutdown type, such event is expected on less than one day a year. However, on the fleet-level (4 or 4.4 GW), the most severe 1 hour downward ramping events are similar for all shutdown types. A very clear reason was not found, but it may be because of storms coming from the west and causing shut-down first for the additional 2.1 GW installations and after some time for the 2.3 GW installations, which can cause an unfortunate aggregate downward ramping event on the fleet-level. The use of HWS technologies remain however very useful for less extreme but more frequent storm events, as discussed further in the report.

Highest 1 h upwards ramping events (restarts) are similar for all studied storm shutdown types. A contributor to this is that the storm shut-down slows only the shut-down and not the restart part of the power curve. However, it needs to be noted that a smoother restart operation after a storm would not remove all extreme upwards ramping events, as they can happen even on low wind days.

2.7. Statistical analysis of forecast errors

2.7.1. Introduction

This Section analyses the simulated forecast errors for the different scenarios. All forecast errors are analyzed on 15 min resolution.

It’s important to note that it would be irrelevant to use simulated forecast errors for one specific event obtained from the time series, as the target is not to replicate the variability due to weather. The analysis is performed aiming at 2 objectives:

- Provide a global statistical analysis, allowing to gain knowledge in forecast errors to be expected in normal and extreme conditions, in particular:
    - Assess if the increased geographical spread of installations impacts the fleet-level forecast errors
    - Study if storm shutdown type impacts the forecast errors
- Provide the expected reduction in fleet-level forecast errors for the years 2018 and 2019 with virtually extended capacity, using the SD reduction factors calculated in this section. This is used as input for the analyses of the impact on Elia’s reserve needs.

Scenarios are compared in standardized generation, as the impact of geographical smoothening is easier to see when all data are standardized, as well as in GW.

The present report focuses on the day-ahead forecast. DTU’s report also includes the results for intraday and latest forecast.

2.7.2. Results

Table 7 shows the day-ahead forecast error statistics for the different scenarios expressed in standardized generation, while Table 8 shows the average number of days per year with at least one day-ahead forecast error more extreme than the given GW limit.

It can be seen that the forecast error SD decreases from the BE 2018 scenario towards the 4.4 GW scenarios. This decrease is due to increased geographical distribution (on aggregate, it is easier to forecast a larger than a smaller region). Tech A and Tech B scenarios show similar statistics. The Deep storm shut-down type shows very slightly reduced likelihoods for very large forecast errors compared to 25 direct cut-off.

Table 7: Day-head forecast error statistics.

									Compared to BE 2018
			mean	SD	Prct 0.001	Prct 0.01	Prct 99.99	Prct 99.999	SD
BE 2018 (877 MW)			-0.002	0.134	-0.952	-0.747	0.741	0.971	100%
Existing (2.3 GW)			-0.001	0.127	-0.791	-0.691	0.648	0.727	95%
3.0 GW	Tech A	25 m/s	-0.001	0.122	-0.731	-0.641	0.616	0.732	91%
3.0 GW	Tech A	Moderate	-0.002	0.121	-0.739	-0.646	0.608	0.682	90%
3.0 GW	Tech A	Deep	-0.002	0.121	-0.731	-0.639	0.607	0.682	90%
3.0 GW	Tech B	25 m/s	-0.001	0.121	-0.710	-0.637	0.606	0.698	90%
3.0 GW	Tech B	Moderate	-0.001	0.121	-0.710	-0.637	0.601	0.679	90%
3.0 GW	Tech B	Deep	-0.001	0.120	-0.710	-0.642	0.598	0.678	90%
4.0 GW	Tech A	25 m/s	-0.001	0.116	-0.702	-0.617	0.589	0.759	87%
4.0 GW	Tech A	Moderate	-0.001	0.115	-0.721	-0.616	0.578	0.673	86%
4.0 GW	Tech A	Deep	-0.001	0.115	-0.695	-0.607	0.570	0.673	86%
4.0 GW	Tech B	25 m/s	-0.001	0.116	-0.681	-0.605	0.576	0.712	87%
4.0 GW	Tech B	Moderate	-0.001	0.115	-0.682	-0.610	0.570	0.681	86%
4.0 GW	Tech B	Deep	-0.001	0.114	-0.681	-0.605	0.566	0.670	85%
4.4 GW	Tech A	25 m/s	-0.001	0.116	-0.700	-0.618	0.601	0.775	87%
4.4 GW	Tech A	Moderate	-0.001	0.115	-0.710	-0.618	0.581	0.680	86%
4.4 GW	Tech A	Deep	-0.001	0.115	-0.688	-0.604	0.571	0.671	85%
4.4 GW	Tech B	25 m/s	-0.001	0.117	-0.697	-0.610	0.584	0.728	87%
4.4 GW	Tech B	Moderate	-0.001	0.115	-0.694	-0.617	0.576	0.682	86%
4.4 GW	Tech B	Deep	-0.001	0.114	-0.677	-0.605	0.569	0.673	85%

Table 8: Day-ahead forecast errors: average number of days per year with at least one event.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	**3.5**	**3.0**	**2.5**	**2.0**	**1.5**	**1.0**	**0.5**	**0.3**	**0.3**	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**
Existing (2.3 GW)								1.4	22.5	139.1	221.6	221.8	138.5	20.7	0.9					
3.0 GW	**Tech A**	**25 m/s**					0.6	7.2	50.5	176.4	248.2	247.6	175.4	47.5	5.9	0.3				
		Moderate					0.6	7.1	49.6	174.6	246.8	245.9	173.2	46.8	5.8	0.2				
		Deep					0.6	7.0	49.5	174.2	246.7	245.9	173.0	46.4	5.6	0.2				
	Tech B	**25 m/s**					0.5	6.6	49.2	178.6	250.0	248.8	175.2	46.5	5.4	0.3				
		Moderate					0.5	6.7	49.0	176.2	248.1	246.8	172.7	45.9	5.3	0.2				
		Deep					0.5	6.6	48.6	175.6	247.8	246.4	172.0	45.4	5.2	0.2				
4.0 GW	**Tech A**	**25 m/s**			0.0	0.8	5.2	25.9	89.5	211.0	270.5	268.7	208.8	84.8	23.4	4.5	0.3	0.1		
		Moderate			0.0	0.7	4.7	24.6	87.7	208.8	268.5	266.6	206.2	82.5	21.8	4.0	0.3	0.0		
		Deep				0.6	4.5	24.2	87.1	208.4	268.3	266.4	205.8	81.6	21.3	3.7	0.2	0.0		
	Tech B	**25 m/s**			0.1	0.6	5.4	26.4	89.6	214.6	273.7	269.6	209.3	84.4	23.6	4.2	0.3	0.1		
		Moderate			0.0	0.6	5.2	25.0	87.2	211.3	270.9	267.0	206.1	81.8	21.6	3.5	0.4	0.0		
		Deep			0.0	0.6	4.9	24.4	86.4	210.6	270.6	266.6	205.2	80.5	20.9	3.3	0.3	0.0		
4.4 GW	**Tech A**	**25 m/s**			0.3	2.0	10.5	37.9	107.9	224.4	278.7	277.7	222.0	101.8	34.6	8.6	1.4	0.1	0.1	
		Moderate			0.2	1.7	9.4	36.2	105.6	222.0	276.9	275.8	219.4	99.2	32.6	7.1	1.1	0.1	0.0	
		Deep			0.2	1.5	9.0	35.8	105.0	221.5	276.7	275.6	219.1	98.2	31.9	6.8	0.9	0.1	0.0	
	Tech B	**25 m/s**			0.2	1.9	11.1	40.2	109.0	227.3	281.8	276.8	222.7	102.5	35.1	9.3	1.4	0.1	0.0	
		Moderate			0.1	1.8	10.1	38.1	105.9	223.9	278.9	274.2	219.4	99.6	32.9	7.4	1.2	0.1	0.0	
		Deep			0.1	1.7	9.5	37.3	104.9	223.2	278.6	273.9	218.8	98.2	31.8	6.9	1.0	0.1	0.0	

DTU's report includes a comparison between forecast errors during days with and without high wind speed, resulting in the conclusion that large forecast errors are more likely during high wind speed days (fleet-level max wind speed > 20 m/s). The Deep type shows slightly lower forecast errors during high wind speeds days compared to 25 direct cut-off.

In addition, an analysis of the forecast errors during days with high ramps (defined as "ramping event > 2 GW") and during storm days (defined as "max wind speed > 20m/s and ramping event > 2 GW") was performed. The conclusions are the following:

- Days with high ramps show higher forecast errors, especially for "Last" forecasts.
- Storm days also show higher forecast errors; however, due to relatively small amount of storm days, the estimation of forecast error distributions is challenging.

It needs to be noted that forecasts are more difficult to simulate than actual generation, as the target is not to replicate the variability due to weather, but to represent the historical forecasts by the Elia's forecast provider and to then estimate future forecast performance in future scenarios. Doing this allows to estimate forecasts and forecast errors resulting from different geographical installation distributions and high wind speed technologies. The actual simulated forecast and forecast error values for an individual event are stochastic, and can be high or low due to randomness.

2.8. Statistical analysis on system imbalance

The purpose of the analyses on system imbalance is the following:

- To support the definition of the scenarios on BRPs' ability to balance incremental renewable capacity
- To analyze differences in the way offshore BRPs historically managed to cover power variations and forecast errors

In Sections 4 and 5, scenarios on BRPs' ability to balance incremental renewable capacity are defined in order to assess the impact of the offshore generation profiles on system imbalance in the future configuration. The analyses performed by DTU on the relations between installed wind power, forecast errors and imbalances supported the reflections on this topic. The analysis was also aimed to better understand how the BRPs' reactions will evolve with extended offshore wind power capacity. Given the other evolutions that have taken place in parallel with the increase of offshore capacity until end of 2019, there were however no very clear correlations identified. Therefore, the scenarios on the BRPs' reactions were defined based on other analyses described in Sections 4 and 5 and the results of this part of the analyses from DTU are not reported here. There are however available in DTU's report in annex.

It's to be noted that it cannot be assumed that the historical BRP reactions will grow linearly as the offshore installed capacity will grow. The historical behavior is only one element in the reflections on this topic, together with the increase of the offshore power variations and the expected evolutions of the system and of the market.

The 2nd objective of this analysis is to analyze differences in the way offshore BRPs historically managed to cover power variations and forecast errors. Most of the statistics provided by DTU for this purpose contain BRP and wind park specific information which can't be disclosed for confidentiality reasons. Therefore, the report in annex is a public version where all references to specific BRPs and parks as well as all information that would allow to deduct specific BRP- or wind park-related information has been removed.

The general conclusion is that significant differences have been observed up to now in the way offshore BRPs manage forecast errors. This could be explained by several factors (available tools, experience in offshore in Belgium and abroad, etc.).

As an example, at individual BRP level, the cross correlation functions from different offshore BRPs show significant differences in correlations between forecast errors and imbalances, as well as in the offshore BRP response in terms of speed of reductions of imbalances. This is illustrated in Figure 13, which represents the cross correlation between day-ahead forecast errors and offshore BRP imbalances. In this figure, a lower correlation between forecast error and imbalance indicates better balancing (lower "initial" imbalance at the time of the forecast error), while a faster reduction of Rxy with increasing lags suggests that imbalances due to forecast errors are reduced faster.

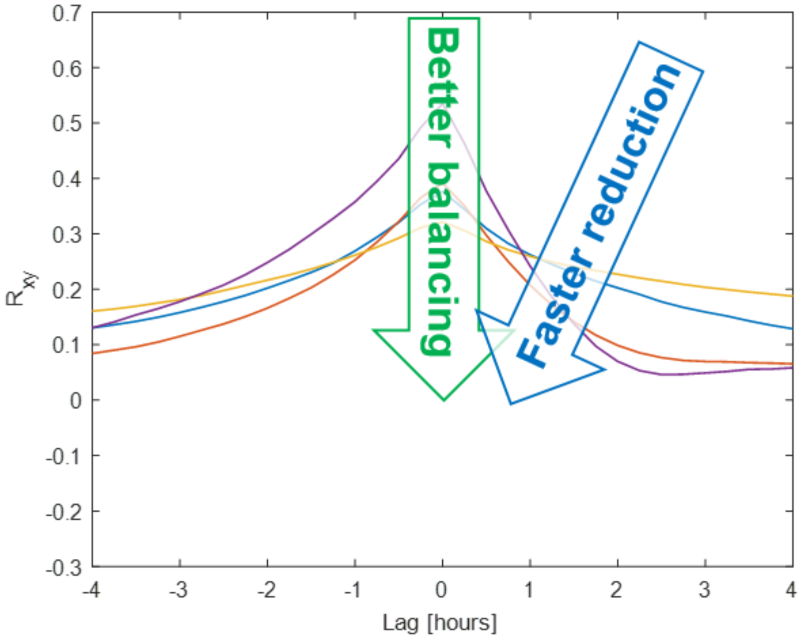


Figure 13: Cross correlation function between BRP forecast errors and BRP imbalances

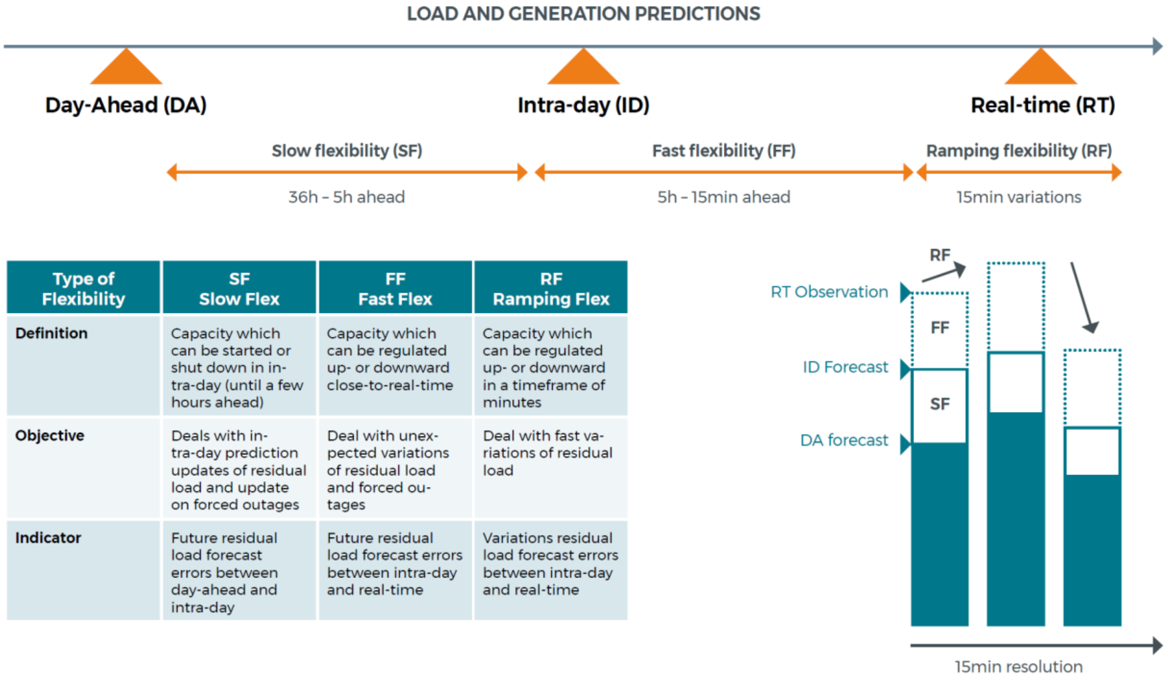
3. Impact on the flexibility needs

In June 2019, Elia published its latest adequacy and flexibility study with projections up to 2030[6]. The two central aspects of this study, adequacy on the one hand and flexibility on the other are both crucial aspects for the well-functioning of the electricity system. Adequacy ensures that the sum of available and expected capacity including imports, are at any time sufficient to meet the demand. The flexibility assessment investigates the extent to which this capacity disposes of the right technical characteristics to cope with future expected and unexpected variations of generation (in particular driven by renewable generation) and demand.

A new methodology was constructed based on analyzing the required (needs for) flexibility and the available (means of) flexibility in three time horizons called (Figure 14):

- **Slow flexibility** represents the ability to deal with expected deviations of demand and generation following the intra-day forecast update. It concerns information received between the day-ahead market (up to 36 hours before real-time) and the intra-day forecast received several hours before real-time, depending on the forecast service. Additionally, this flexibility deals with outages of power plants or transmission assets which are announced several hours before real-time (or still not resolved after several hours). This flexibility can be provided with most of the installed capacity as there are several hours to change the output of a generation, storage or demand unit and even start or stop a power plant.
- **Fast flexibility** represents the ability to deal with unexpected power deviations in real-time, or deviations for which information is received between the last intra-day forecast and real-time. It concerns information received between several hours up to a few minutes before real-time, depending on the forecast service. Additionally, this flexibility type needs to deal with forced outages up to several hours until the providers of slow flexibility can take over. Fast flexibility can be provided with generation units which are already dispatched and able to realize a modification in their output program within a few minutes, or units which have start or stop time in a few minutes, as well as storage units (pumped-hydro and batteries) and types of demand-side management which are considered very flexible.
- **Ramping flexibility** represents the ability to deal with the real-time variations of the forecast error and in particular the forecast errors of the last intra-day forecast before real-time. It can be expressed as capacity required up to 5 or 15 minutes, or per minute (MW/min). This type of flexibility does not cover forced outages which are assumed to be covered by FCR, and relieved by fast and slow flexibility. Ramping flexibility is to be covered by assets which can follow forecast error variations on a minute-basis and therefore only those units which are already dispatched, as well as some battery storage and demand-side management which are considered very flexible.

[6] **https://www.elia.be/en/electricity-market-and-system/adequacy/adequacy-studies**



Type of Flexibility	SF Slow Flex	FF Fast Flex	RF Ramping Flex
Definition	Capacity which can be started or shut down in intra-day (until a few hours ahead)	Capacity which can be regulated up- or downward close-to-real-time	Capacity which can be regulated up- or downward in a timeframe of minutes
Objective	Deals with intra-day prediction updates of residual load and update on forced outages	Deal with unexpected variations of residual load and forced outages	Deal with fast variations of residual load
Indicator	Future residual load forecast errors between day-ahead and intra-day	Future residual load forecast errors between intra-day and real-time	Variations residual load forecast errors between intra-day and real-time

Figure 14: Overview of the three types of flexibility studied in the flexibility study (adequacy and flexibility study 2019)

The **flexibility needs** are calculated based on a statistical analysis of generation and prediction forecasts of wind and solar power, demand and must run generation, as well as the forced outage characteristics of the thermal generation fleet and the relevant HVDC-interconnector. These profiles are based on an upscaling of historical data taking into account system evolutions. These needs are then compared with the **available flexibility means** which are calculated by means of the available up- or downward on the nominated generation or demand of all generation, demand response and storage units in the system, as well taking into account cross-border capacity. This is based on the market simulations conducted in the adequacy study and therefore represents available non-guaranteed flexibility.

In this study, the projections of the needs and means already included the 2nd wave of offshore. In fact, it was shown that flexibility needs are expected to increase towards 2030 following the further integration of variable renewable capacity such as wind power and photovoltaics. The new offshore wind power development, with the ambition to achieve 4.0 GW of installed capacity, is one of the main drivers for these increasing needs. On the other hand, the study also shows that the required flexibility will be installed in the system, assuming the system is adequate. However, this flexibility may not always be available when needed without upfront reservation (by the market or by Elia) to cover unexpected variations of generation and demand.

All details on the methodology and results of the flexibility study can be found in the related report. The objective of this study is not to re-conduct the flexibility study but to update it with the new information on the future offshore wind power capacity to be installed towards 2028, increasing to 3.0 GW in 2026 and 4.4 GW in 2028, and the high resolution time series provided by DTU confirm these results and conclusions.

3.1. Methodology

The methodology of the adequacy and flexibility study 2019 is used to update the flexibility needs towards 2028. **The only methodological update that has been conducted is to increase the resolution of the offshore generation data from 15 to 5 minutes**, as provided by DTU in the framework of this study (see Section 2.3.3). To calculate the ramping flexibility, Elia's 15' available generation profiles for onshore and solar generation are linearly interpolated towards 5'. For the fast and slow flexibility, no methodological changes were required as Elia's 15' resolution data is only replaced by DTU's 15' resolution data. It is to be noted that periods with storms are removed from the dataset as these are studied in detail as exceptional conditions in Section 5. Other non-methodological updates concern:

- replacing Elia's 2017-18 generation and forecast time series with 2018-19 time series;
- updating the installed capacity for offshore with the 3.0 GW (2026) and up to 4.0 - 4.4 GW (2028).

It is investigated if the results and conclusions of the last study hold when making these updates. Note that the time series of DTU allow to capture better the geographical smoothing effects when installing a 2nd wave of offshore generation. In addition, it also allows to assess if the method for upscaling from one installation zone to another - as previously done in the flexibility study – can be sufficiently accurate. Finally, by comparing the results with the available means – which are not updated as there are no new elements which are expected to substantially impact the results, the conclusions can be confirmed or updated as well.

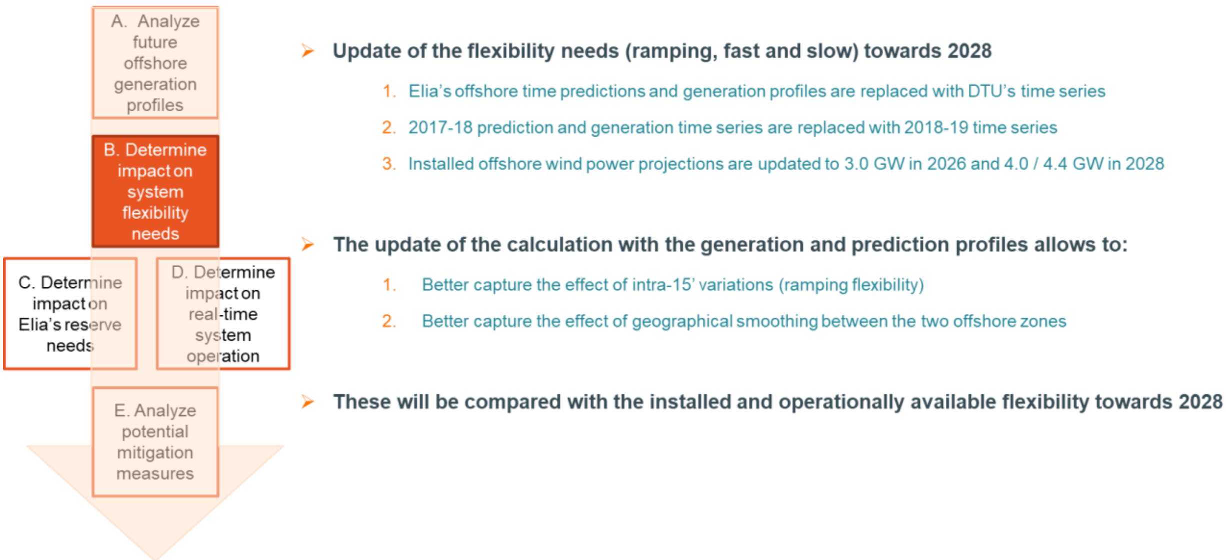


Figure 15: overview of the methodology to update the flexibility needs

3.2. Scenario's and assumptions

This study will start from the scenarios put forward in the latest adequacy and flexibility study as these remain relevant today. However, the low renewable capacity scenario is not conducted anymore as it became less probable with the 'Green Deal' plans of the European Commission. In addition, the different demand scenarios were not conducted as the previous study has shown the limited impact of these sensitivities on the results. All projections are conducted for 2028 and 2026, which are two main years of interest for this study, complemented with 2020 and 2023.

Considering the offshore wind technologies, the impact of cut-out technologies are not investigated as the storms are excluded from the data. For the two technologies Tech A and Tech B options, discussed in Section 2.2, the impact on flexibility and reserves are expected to be minimal and only Tech B is selected for the analyses (having the steepest ramp and is therefore expected to result in higher variability).

Also the impact of the scenario where the nuclear units are not replaced by larger units of around 600 – 800 MW, but by small units of around 100 – 200 MW, is not investigated as it was already show in the adequacy and flexibly study that the impact on the total flexibility needs is limited. However, it might have an effect during particular conditions (e.g. periods with risks on scarcity) and also on reserve dimensioning for which this scenario is investigated (Section 4).

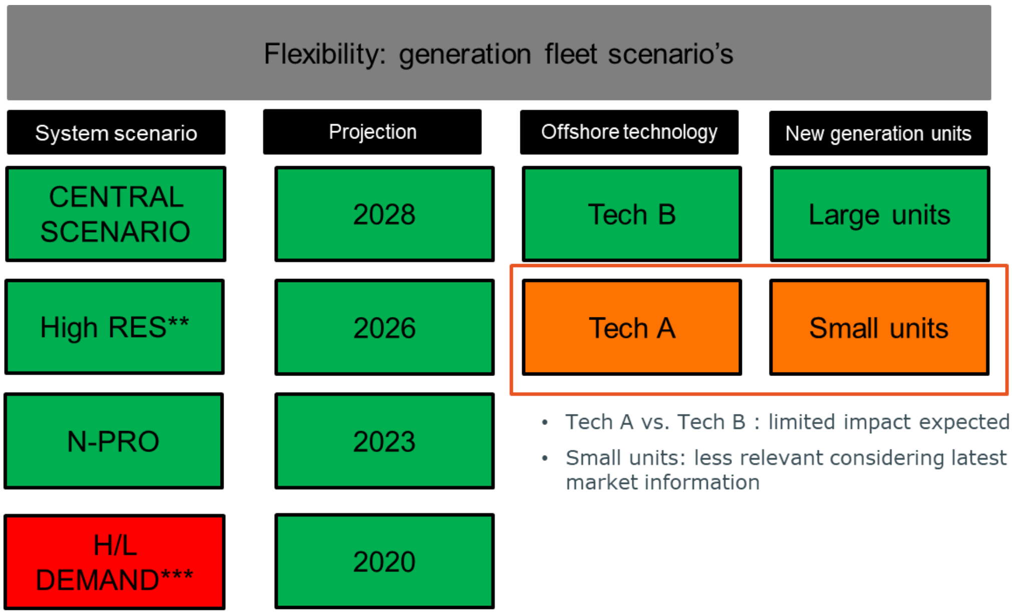


Figure 16: Overview of investigated scenarios

3.2.1. Installed generation capacity

Same projections of installed capacities of the Belgian generation fleet are used as in the latest adequacy and flexibility study. Only modification concerns the offshore generation fleet where the installed capacity is increased from **2.3 GW to 3.0 GW to 2026 and 4.0 GW to 4.4 GW in 2028**. Note that an additional scenario for 4.0 GW was foreseen to be investigated as well. However, it is not further discussed in this section as the impact on the flexibility needs is minor and does not impact the conclusions of the study. In contrast, it is discussed in Section 4 dealing with the impact on reserve capacity needs.

Table 9: installed capacity for wind and solar power towards 2030 (figures in red are updated compared to the previous study)

	Generation capacity at the end of the mentioned year [MW]														
CENTRAL SCENARIO	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Wind CENTRAL	**2,371**	**2,774**	**3,305**	**4,123**	**5,046**	**5,210**	**5,374**	**5,537**	**5,701**	**5,865**	**6,7**	**7.5**	**8,4**	**8,7**	**8,7**
Wind onshore	1,658	1,915	2,254	2,513	2,775	2,939	3,103	3,266	3,430	3,594	3,765	3,936	4,107	4,279	4,450
Wind offshore	713	859	1,051	1,610	2,271	2,271	2,271	2,271	2,271	2,271	3.0	3.6	4,4	4,4	4,4
Photovoltaics CENTRAL	**3,200**	**3,587**	**3,932**	**4,433**	**5,070**	**5,600**	**6,262**	**6,925**	**7,587**	**8,249**	**8,800**	**9,351**	**9,903**	**10,454**	**11,005**
HIGH RES SCENARIO	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Wind - HIGH	**2,371**	**2,774**	**3,305**	**4,123**	**5,046**	**5,297**	**5,549**	**5,800**	**6,051**	**7,031**	**4,286**	**8,134**	**9,2**	**9,4**	**9.7**
Wind onshore - HIGH	1,658	1,915	2,254	2,513	2,775	3,026	3,278	3,529	3,780	4,031	4,283	4,534	4,785	5,036	5,288
Wind offshore - HIGH	713	859	1,051	1,610	2,271	2,271	2,271	2,271	2,271	3,000	3,000	3,600	4.4	4,4	4,4
Photovoltaics - HIGH	**3,200**	**3,587**	**3,932**	**4,433**	**5,070**	**5,960**	**6,850**	**7,741**	**8,631**	**9,521**	**10,411**	**11,302**	**12,192**	**13,082**	**13,973**

*An additional scenario is analyzed with a maximum capacity of 4.0 GW

3.2.2. Renewable / decentral generation and load time series

Prediction data of total load and renewable generation are based on dedicated forecasting tools for which the real-time results are published on Elia's website. Although the flexibility needs of the system are driven by the predictions and operational decisions of market players, this forecast data is assumed to be representative for the tools used by market players. In this flexibility assessment, the time series of offshore generation and forecast data is replaced without further corrections by time series provided by DTU, estimating the generation and forecasts in 2026 and 202. This data is discussed in Section 2.3.3.

For the time series of Elia, the estimated or observed total load, renewable and distributed generation are based on measurements, monitoring and upscaling. The forecasted (day-ahead, intra-day and last forecast) values are obtained from external service providers. A correction of the forecast error is done when Elia activates a decremental bid on these units. In order to take a representative data set into account, two subsequent full years (2018 and 2019) are selected. For future forecast improvements, an average cumulative improvement factor of 1% per year is taken into consideration between 2018-19 and 2028. This means that the forecast error is corrected to 99.0% of its value towards 2020, by means of a factor $(1 – 0.01)^y$ with y the amount of years for which the forecast errors are to be extrapolated. This will result in a reduction of the original forecast errors of 2018-19 down to 91.4% of their original values in 2028.

These forecast accuracy improvements are mainly attributed to increasing geographical dispersion, smoothening out prediction errors. No significant improvements are expected for the weather forecast models (except maybe for better predicting extreme weather conditions). On the contrary, the integration of new technologies such as electric vehicles, heat pumps and other decentral capacity is expected to result in new patterns which increase the complexity of forecasting prediction tools.

3.3. Results

3.3.1. Central scenario

Figure 17 shows the flexibility needs compared to the results of the previous study (note that 2026 was not explicitly dealt with in the previous study and results are calculated with the same method and data as in the latest adequacy and flexibility study). Main observations is that the ramping flexibility needs (expressed here in MW which may need to react in five minutes in line with the new resolution used) increases towards 2028. Figure 17 also shows that the total flexibility (sum of the fast flexibility and slow flexibility) remains almost unchanged, or faces a small reduction towards 2028 for downward flexibility. Figure 17 shows similar trends for the downward ramping flexibility needs.

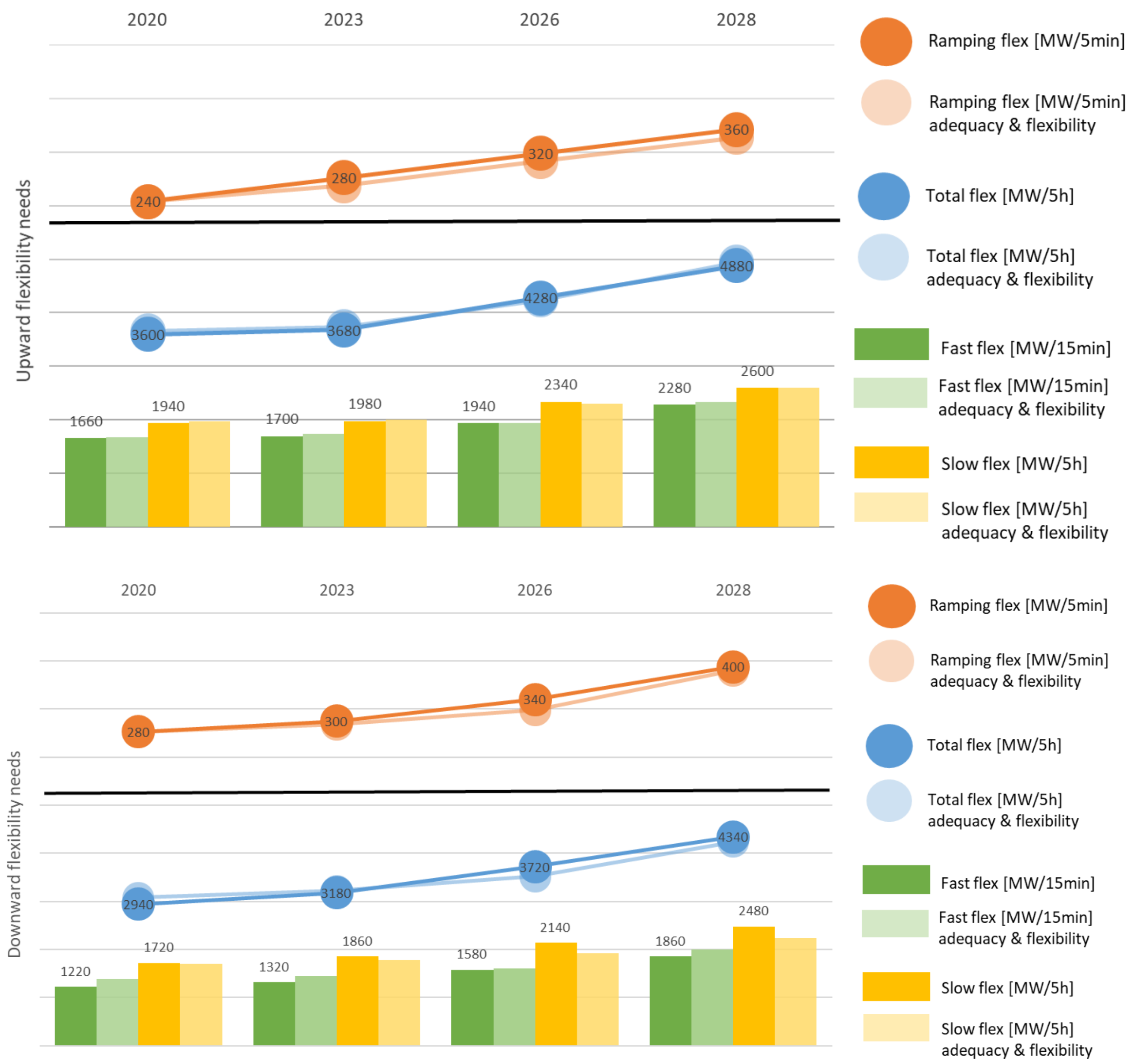


Figure 17: up- and downward flexibility needs in the CENTRAL scenario toward 2028 (expressed in MW)

Figure 18 conducts a step-by-step analyses to explain for 2028 the impact of:

- the update of the offshore installed capacity;
- the update of the time series for 2017-18 to 2018-19;
- the update of the offshore generation and prediction extrapolations with DTU time series;
- the increase in resolution for the generation profiles to 5' (impact only on the ramping flexibility).

It can be seen that the increasing up- and downward ramping flexibility needs in 2026 and 2028 are explained by the installed offshore capacity and the increase in resolution towards 5', while being partly counteracted by the use of the DTU time series, better capturing the geographical smoothing effects when commissioning a 2nd wind park. For the same reason, the fast flexibility needs are found to be lower than in the adequacy and flexibility study as the increasing capacity installed in 2026 and 2028 is largely compensated by the reductions following the use of DTU time series. However, the effect of the DTU data on the downward intra-day forecast errors seems lower.

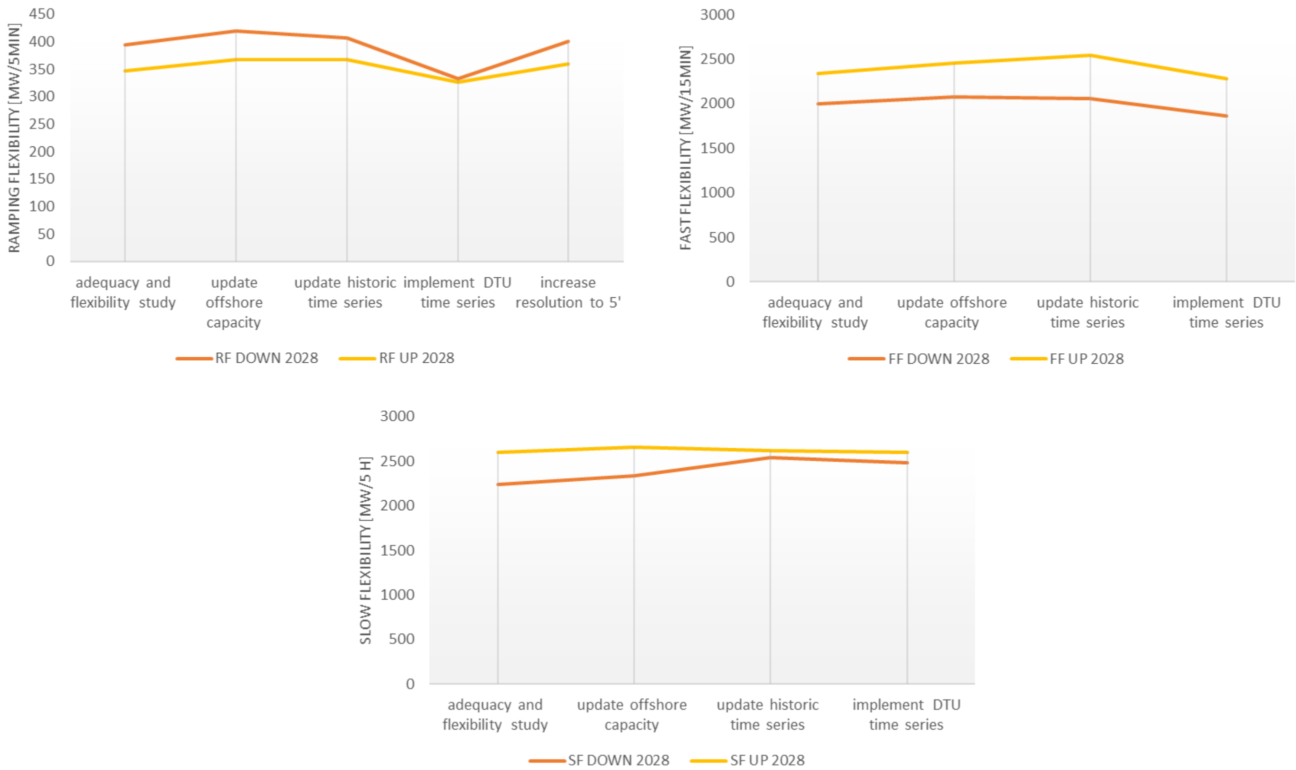


Figure 18: impact assessment of the different updates compared to the adequacy and flexibility study 2019

In conclusion, besides an increase in the ramping flexibility needs due to increasing the resolution towards 5', and a reducing effect of geographical smoothing using DTU's time series for 2026 and 2028, this analysis confirms the results and conclusions of the adequacy and flexibility study 2019. However, the DTU generation and forecast profiles for offshore wind power reduce the flexibility needs by taking into account the geographical smoothing effects of the 2nd wave of offshore wind. Still, the effect remains relatively minor showing that previous extrapolations of the Elia forecast and generation data for analyses concerning flexibility and reserves already provide good results as well.

3.3.2 Sensitivities

Figure 19 shows the results of the H-RES scenario, i.e. additional onshore wind and solar power, comparing it to the results of the same scenario in the previous study. In general, same trends and conclusions are observed as in the CENTRAL scenario. In the H-RES scenario, all flexibility needs are higher which is explained by the higher onshore and solar installed capacities than in the CENTRAL scenario. Namely onshore installed capacities are expected to increase from 3.2 GW, 3.8 GW and 4.1 GW in 2023, 2026 and 2028 respectively in the CENTRAL scenario to 3.5 GW, 4.3 GW and 4.8 GW for the same respective years in the H-RES scenario. Regarding solar installed capacities, these are expected to increase from 6.9 GW, 8.8 GW and 9.9 GW in 2023, 2026 and 2028 respectively in the CENTRAL scenario to 7.7 GW, 10.4 GW and 12.2 GW for the same respective years in the H-RES scenario.

Note that for the N-PRO scenario, i.e. the nuclear prolongation, the investigation did not prove any significant effect on the required flexibility needs. This is also in line with the results of the latest adequacy and flexibility study although an impact was observed in particular periods, i.e. during periods with a risk for scarcity. This is again expected to be the case (although not the scope of this study) and also an effect on reserve dimensioning is expected (which is investigated in Section 4).

Figure 19: upward (up) and downward (down) flexibility needs in the H-RES scenario toward 2028 (expressed in MW)

3.3.3. Impact of geographical smoothing

While the previous sections shows the mitigating effect when replacing Elia's offshore wind power extrapolations with DTU's time series including the geographical smoothing effect of the 2nd wave of offshore wind power, it is also shown that the effect is not large and that the former extrapolation of the Elia 15' resolution forecasts and measurements already provided good estimations. This performance is even expected to further increase when available data increases with more wind parks being commissioned.

Figure 20 depicts this effect when comparing the day-ahead forecast errors of the DTU 4.4 GW time series and the DTU 2.3 GW, and even the historic Elia 2018-19 time series. Both depict the forecast error reductions which can be attributed to geographical smoothing of larger offshore wind power capacities being installed.

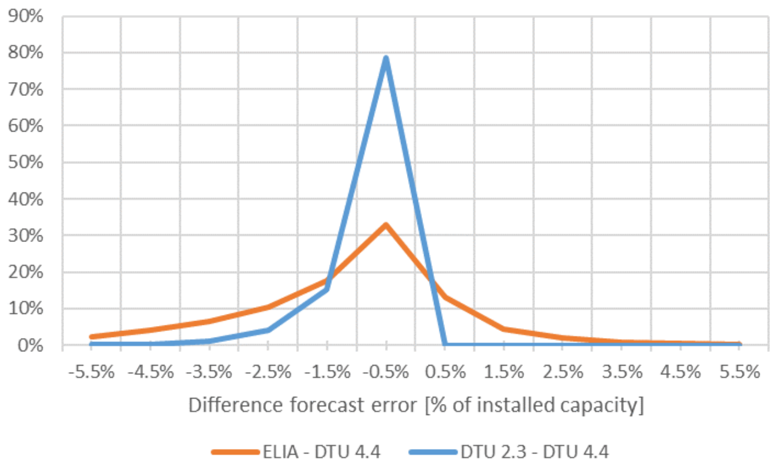


Figure 20: distribution of the difference in day-ahead forecast error (expressed as percentage of installed capacity) between DTU 4.4 GW time series DTU 2.3 GW or Elia's historic 2018-19 time series

3.3.4. Impact of increased time series resolution

The previous section has shown that the increasing resolution of the production data from 15' to 5' increases the ramping flexibility, at least when assessing the ramping flexibility on 5' resolution or lower. While in absolute terms, the variations to be covered are obviously reduced when looking at a lower resolution, the ramping flexibility increases when assessed on 1 or 5 minute basis as shown in Table 10.

This table depicts the high and low percentiles of the 15' and 5' variations of the last forecast error for offshore wind power and all technologies in 2028. Obviously, while the absolute figures are strongly reduced, this is not the case when assessed the same figures on a minutely basis where they drive the ramping flexibility needs up. This means intra-15' variations do have an impact on the results, requiring fast response. Note that this effect is largely reduced with the aggregation with the other technologies.

In conclusion, the impact on intra-15' variations might be relevant towards future studies and projections, although the effect is not to be overestimated as when investigating this on system level, i.e. when aggregated with other renewable generation sources which are more geographically dispersed, the effect of increasing resolution becomes less relevant, at least for analyses towards system-wide flexibility and reserve needs.

Table 10: Last forecast error variations for offshore wind (Δ LF PE wind) and aggregated over all technologies (Δ LF PE all drivers) on a 15 minute and 5 minute basis

	2028 DTU 15 min		2028 DTU 5 min		2028 DTU 15 min (expressed per minute)		2028 DTU 5 min (expressed per minute)	
percentiles	**Δ LF PE all drivers**	**Δ LF PE offshore wind**	**Δ LF PE all drivers**	**Δ LF PE offshore wind**	**Δ LF PE all drivers**	**Δ LF PE offshore wind**	**Δ LF PE all drivers**	**Δ LF PE offshore wind**
0.99	428	711	157	553	29	47	31	111
0.95	230	400	82	311	15	27	16	62
0.9	163	258	57	200	11	17	11	40
0.1	-164	-356	-57	-277	-11	-24	-11	-55
0.05	-234	-536	-83	-417	-16	-36	-17	-83
0.01	-447	-945	-168	-733	-30	-63	-34	-147

3.4. Available flexibility means

It is already mentioned that no new simulations were conducted in the framework of this study concerning the flexibility means. First of all, no new elements justified to re-conduct the market simulations in the latest adequacy and flexibility study to re-assess the day-ahead schedule of the future system (i.e. generation units, storage, demand response and import / export). Secondly, the new results for the flexibility needs are not impacted to an extent which will impact the trends and conclusions. It is therefore confirmed that **if the system is adequate, sufficient flexibility will be installed in the system, but it will not always be operationally available when needed:**

- Installed capacity in the system will be sufficient to cover the flexibility needs
- Operational flexibility has to be secured upfront to ensure availability when needed
- Technologies such as storage and demand response will increasingly contribute to flexibility

A specific analysis is however conducted to investigate if more flexibility will be available towards 2030 in periods with high offshore wind generation. This is particularly relevant when studying downward ramping events and storm events as these require upward flexibility when high wind conditions were predicted. For this analysis, the available ramping and fast flexibility is investigated during a subset of periods where offshore generation is predicted to be maximal. The slow flexibility is not investigated as these types of unpredicted events require units which are able to react fast. Note that for this analysis, 2030 is assumed to be representative towards 2028 and 2026 which is expected to give a fair estimation as no fundamental evolutions are currently expected after 2026.

Table 11 shows the available up-and downward flexibility as calculated in the flexibility study. It investigates the tails of the probability distribution curves of the ramping (RF) and fast flexibility (FF) during high wind conditions in 2030. It is concluded that in first instance, no substantial amounts of additional upward flexibility are observed on the thermal and non-thermal flexibility provided in Elia's LFC block as the results are similar to the results in the adequacy and flexibility study. Note that this only means that reservation might be necessary by BRPs or TSO and does not provide conclusions on the related costs.

Table 11: available flexibility means during all periods (adequacy and flexibility study 2019)

MEANS [MW]		2020			2025			2030		
		AVG	P99.0	P99.9	AVG	P99.0	P99.9	AVG	P99.0	P99.9
UP	ramping	199	98	92	730	24	12	1087	18	11
	fast	1197	513	507	1825	449	442	2237	487	480
	total	8480	4831	3355	9371	5468	3227	11253	6075	1532
DOWN	ramping	1235	155	100	1501	24	17	1735	24	13
	fast	3813	2136	1453	4412	1616	1219	4943	1423	1088
	total	10622	8675	7443	11980	8642	7556	12391	8218	7473

Table 12: available upward ramping flexibility (RF) and fast flexibility (FF) without and with additional remaining intra-day cross-border capacity (ATC ID) during high wind periods

PERCENTILE	RF [MW/1min]	FF [MW/15min]	RF + ATC ID	FF +ATC ID
0.1	30	493	1190	6488
0.05	24	493	1027	5735
0.01	18	487	761	4461
0.001	11	480	323	3443

However, it is found that remaining cross-border capacity after day-ahead during these periods is substantially larger. Note that in the last adequacy and flexibility study, this participation was capped at 50 MW, representing the capacity of the mFRR sharing taken into account as "firm" in the dimensioning of reserve capacity. However, with the integration of additional borders, via Nemo Link and ALEGrO, as well as the further integration of the European balancing market with the exchange of non-contracted balancing energy via PICASSO and MARI, this might be a rather conservative estimation.

Therefore, Table 12 shows only the potential impact if all remaining cross-border capacity would be taken into account (note that for the ramping flex, the available capacity is divided by 5 assuming an activation of at least 5 minutes based on the future full activation time of aFRR). It is clear that taking into account all this capacity in future analyses would be way too progressive as it is not clear which volumes will be available on PICASSO and MARI in 2026 and 2028. This is subject to many uncertainties (e.g. geographical correlations of unpredicted variations between LFC blocks following offshore wind parks in Northern France and the Netherlands). In conclusion, some additional capacities are expected to be available but extreme caution is advised when taking (part of) this capacity into account.

A similar analysis is conducted for **downward flexibility during low wind conditions**, which is relevant for the upward ramping events of offshore generation. However, it is important to notice that upward ramping events could, technically, always be resolved by means of curtailment or self-curtailment. Table 13 shows the same observations as with upward flexibility: there is not a substantial impact on the local thermal and non-thermal flexibility, but available export capacity can be substantial. The same disclaimers as above have to be taken into account.

Table 13: available downward ramping flexibility (RF) and fast flexibility (FF) without and with additional remaining intra-day cross-border capacity (ATC ID) during high wind periods

PERCENTILE	RF [MW/1min]	FF [MW/15min]	RF + ATC ID	FF +ATC ID
0.1	265	2576	1821	9803
0.05	102	2157	1632	9029
0.01	30	1215	1488	7873
0.001	17	880	1395	6480

4. Impact on the reserve capacity needs

This section studies the impact of the 2nd wave of offshore generation, increasing the installed capacity from 2.3 GW to maximum 4.4 GW, on Elia's FRR reserve capacity needs. This is the part of the flexibility needs which is dimensioned and activated by Elia to deal with LFC block imbalances. Note that Elia's FRR reserve capacity needs are dimensioned according to a dynamic methodology specified in the LFC block operational agreement, approved by the NRA, where FRR needs are determined in day-ahead with a resolution of 4-hours.

The methodology is based on a **probabilistic methodology** estimating the imbalance risks for each quarter-hour of the next day and determining the required reserve capacity on FRR to cover 99.0% of the imbalance risks, i.e. the 99.0% percentile of the probability distribution curve of the positive and negative LFC block imbalances. The probabilistic method is based on machine learning algorithms relating the imbalance risk to day-ahead predicted system features such as renewable generation, demand, weather conditions, as well taking into account the imbalance risks due to forced outages of available power plants and the Nemo Link interconnector.

In parallel, Elia considers the dimensioning incident by means of a **deterministic methodology**. This method has to ensure that the positive and negative FRR needs shall not be less than the positive and negative dimensioning incident of the LFC block, as required by Article 157(2)e and 157(2)f of the SOGL. The dimensioning incident is defined by Article 3 of the SOGL as the highest expected instantaneously occurring active power imbalance within a LFC block in both positive and negative direction.

Finally, Elia applies an additional **minimum threshold** to ensure that the required positive and negative reserve capacity is sufficient to cover at least the positive and negative historic LFC block imbalances for 99.0% of the time in order to be in line with Articles 157(2)h and 157(2)i of the SOGL.

This means that the final FRR needs are determined partially by the ability of the market to maintain the balance in their portfolio. The projections made in this study are estimations made by Elia based on scenarios concerning future market evolutions. They aim to understand the effect of the growth in offshore generation fleet on the reserve capacity needs and to identify potential challenges and required mitigation measures.

Note that this study will also implement an estimation of the aFRR needs with the current methodology, knowing that this methodology is currently under review in another study and projections on the aFRR needs with this new methodology are only expected in September 2020. Finally, FCR is not investigated as it is determined on European level and no substantial impact is expected resulting from FCR.

4.1. Methodology

Figure 21 gives a visual representation of the methodology to make these projections. In a **first step**, scenarios are composed on future **BRP ability to balance their portfolio**. This is based on an analysis of historic LFC block imbalances, BRP portfolio imbalances and offshore generation day-ahead and intra-day forecast errors. The scenarios take into account best and worst case estimations on future market performance in dealing with offshore LFC block imbalances.

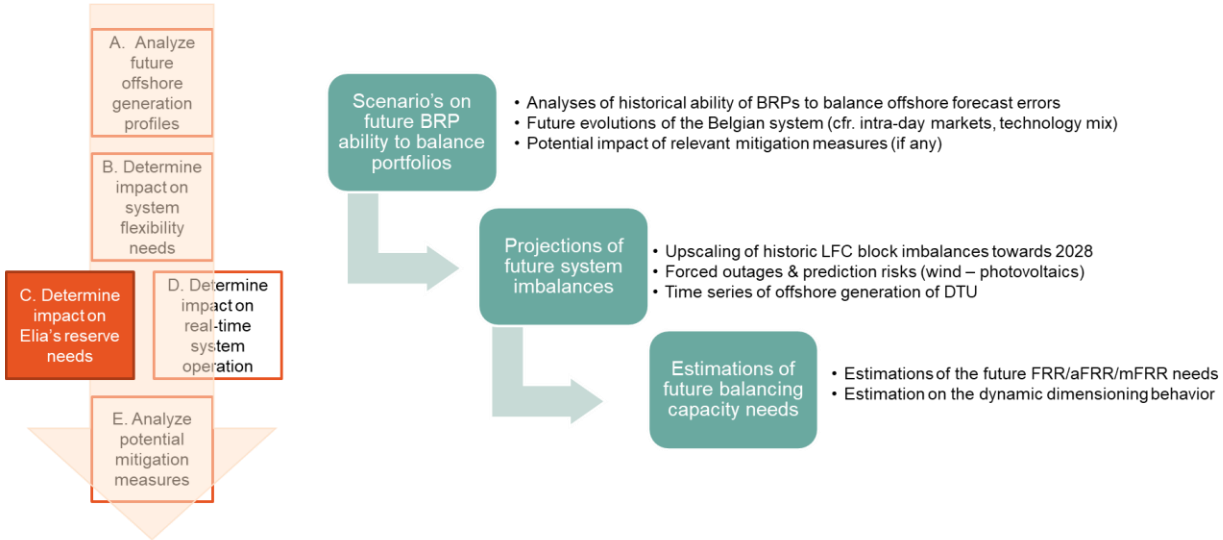


Figure 21: Overview of the methodology to determine the impact on the reserve capacity needs

In the **second step**, historic **LFC block imbalances of 2018 and 2019 are up-scaled towards 2023, 2026 and 2028**. The historic time series is extrapolated by taking into account expected system evolutions between the period representing historical records and the period for which the FRR needs are to be determined. For every quarter-hour, the LFC block imbalance (*SI_t*) is increased or decreased with the expected forecast errors (*$FE_{t,i}$*) resulting from the incremental capacity of each technology *"i"*, i.e. onshore / offshore wind power and photovoltaic power. Correlations between system imbalances and forecast errors are taken into account by always using the same period "*t*" for every parameter. For every quarter-hour "*t*", the expected LFC block imbalance in 2020 (Baseline) is calculated as:

$$Baseline_t = (SI_t + \sum_i IC_{t,i} * FE_{t,i} * A_i * B_i * C_i), \quad for\ i = wind\ onshore, wind\ offshore, pv$$

- ***$FE_{t,i}$* = (*$DA_{t,i}$* – *$RT_{t,i}$*) / *$MC_{t,i}$***
  - *$DA_{t,i}$: day-ahead forecast [MW]*
  - *$RT_{t,i}$: real-time estimation [MW]*
  - *$MC_{t,i}$: monitored capacity [MW]*

  For onshore wind and solar power historic time series are obtained from Elia's forecast tools as published on the website of Elia. For offshore wind power, the time series for the 4.4 GW, 4.0 GW, 3.0 GW and 2.3 GW offshore generation park are obtained from DTU.

- ***$IC_{t,i}$* :** for every technology "i", the difference between the installed capacity between the year corresponding to the period "t" in the historic time series of LFC block imbalances, and the 2023, 2026 and 2028. These values are already specified in Section 3.2.1.

- **$A_i = 1 - X_i{*}Y_i$** : improvement factor representing the forecast accuracy improvements following intra-day predictions (X_i) and the ability of the BRP to adjust its portfolio following this information (Y_i). These are based on the scenarios elaborated in the first step and discussed in Section 4.2.2.
- **B_i : $(1-Z_i)$** : improvement factor representing the improvement (Z_i) in LFC block imbalance quality following Elia's continuous efforts to incentivize and help BRPs balancing their portfolio based on the scenarios elaborated in the first step and discussed in Section 4.2.1.
- **C_i : $(1-W_i)$** : improvement factor representing the improvement (W_i) of the day-ahead forecast error following the improvement in renewable generation forecast tool and discussed in Section 4.2.3.

To calculate the FRR needs, a probability distribution is made of the LFC block imbalances and convoluted with the probability distribution of the forced outages of larger generation units. Here, the same list of relevant power plants is taken as in Section 3.2.1 based on the adequacy and flexibility study 2019.

In the **third step**, the current methodology is used to simulate based on these projections the dynamic FRR needs. The upscaled LFC block imbalances are set against the database of predicted system features as specified in the LFC Block Operational Agreement to simulate the result of the probabilistic approach. Part of the dataset is used to train the algorithms, the other part is to make simulations for 2023, 2026 and 2028. This allows to determine the average FRR needs, as well as the occurrence of these FRR needs, taking into account the deterministic methods based on the dimensioning incident and the minimum legal threshold.

Finally, an estimation is made of the current aFRR needs based on the current methodology (for which Elia investigate opportunities for improvement in a separate study) to determine the ratio between aFRR needs and mFRR needs.

4.2. Scenarios and assumptions

In order to make projections for future FRR reserve capacity needs, assumptions have to be made concerning future performance of variable renewable forecast tools, as well as the market's ability to balance portfolio imbalances. For this, three cases on market performance are presented in Figure 22 based on historic observations and estimations on future behavior: a reference case, a worst case and a best case. These cases are conducted for the CENTRAL scenario concerning the future generation fleet as elaborated in Section 4.2.

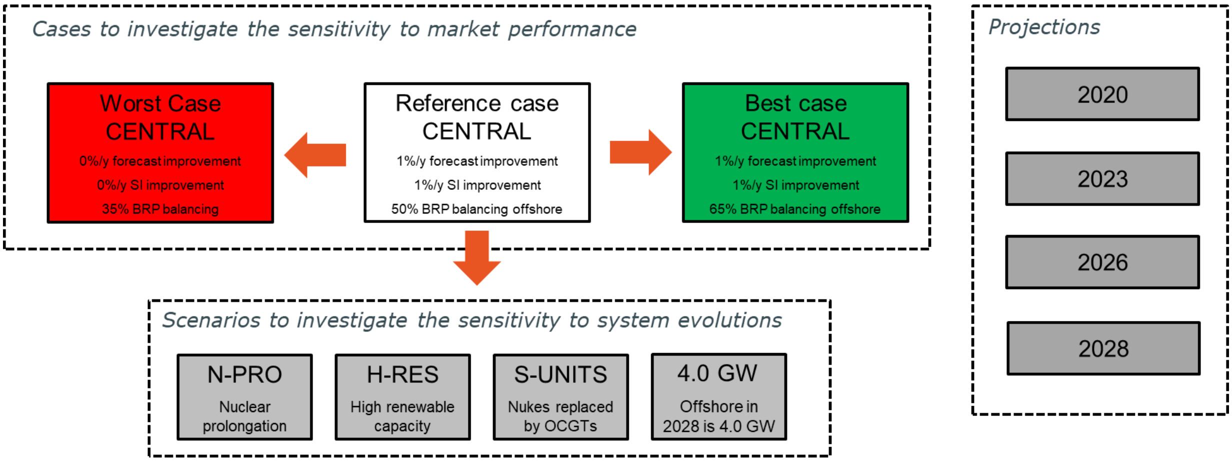


Figure 22: overview of the scenario's and cases for the projections

Note that for the forced outage risk, the list of large generation units is taken from the latest adequacy and flexibility study, assuming replacing the nuclear units with larger units of around 600 – 800 MW. Hence, a sensitivity where these are replaced with smaller units of around 100 – 200 MW. As the schedule of Nemo Link plays a role in the FRR needs estimations, a representative time series is taken for the schedule of Nemo Link in 2028 based on the simulations conducted in the latest adequacy and flexibility study for the CENTRAL scenario.

The CENTRAL scenario is complemented with the other four scenarios elaborated in Section 0 which are investigated for the reference case in market performance. Based on this set of scenarios and cases, projections are made for 2020, 2023, 2026 and 2028.

4.2.1. LFC block imbalance quality

To derive scenarios on the yearly improvement of the LFC block imbalance quality, Figure 23 depicts the yearly improvement of the absolute values of the LFC block imbalance between 2012 and 2019 (expressed as percentage of the previous year). Results show that between 2011 - 2019, a yearly average reduction of the absolute average value of 4.5% was observed. This is more or less the same for the same for the largest imbalances where the average reduction of 3.6% was observed

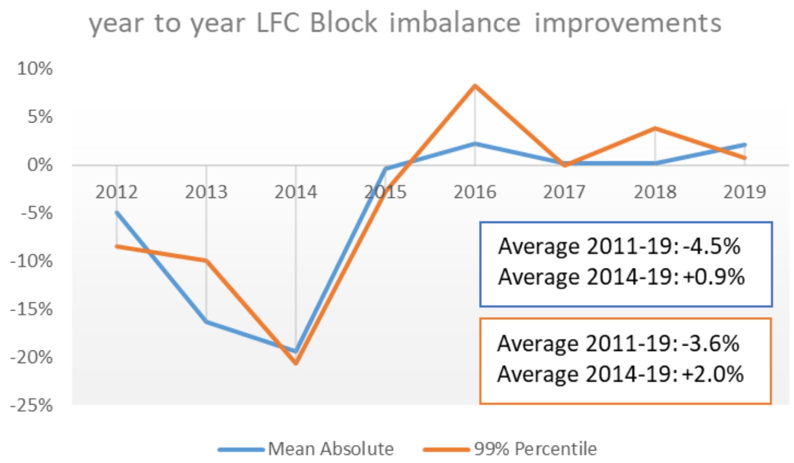


Figure 23: improvement of the mean absolute and 99% percentile LFC block imbalance compared to the previous year

However, Figure 23 also shows that since 2015, the yearly improvement factor stabilized around 0% with even a slight reduction of quality in 2019. The yearly average reduction between 2014 - 2019 becomes an average increase of 0.9% per year. This increase even reaches 2.0% per year when looking at the largest imbalances. It is mainly due to the increasing share of renewable generation in the system. However, by means of its continuous efforts to provide the market with the right tools and incentives to balance their portfolio, Elia hopes to keep the LFC block imbalance quality at least stable, i.e. at 0%. However, in the reference case and best case, Elia estimates to achieve a yearly improvement of one percent per year. Note that in the latest LFC block operational agreement, a yearly improvement of 2% was still assumed, which is, considering the latest observations in 2019, revised down.

However, with its continuous efforts to provide the market with the right tools and incentives to balance their portfolio, Elia hopes to keep the LFC block imbalance quality at least stable, i.e. at 0%. However, in the reference and best case, Elia estimates to achieve a yearly improvement of one percent per year.

4.2.2. BRP ability to balance incremental variable renewable capacity

The ability for BRPs to deal with offshore generation in their portfolio depends on various things. Important is the access of individual BRPs to flexibility. As shown in the analysis of DTU, this ability can vary from BRP to BRP but on average, this is only expected to improve in the future due to better markets. Note that the flexibility is also not necessarily to be found physically in the BRP's portfolio, but can also be accessed via intra-day markets, imbalance pooling and even trough reactive balancing (where BRPs help to balance the system by activating flexibility in their portfolio reacting on imbalance settlement prices).

A first indicator which is used to build the scenarios on LFC block imbalance projections are the intra-day forecast updates, i.e. the evolution of the forecast error when going from the day-ahead to the last forecast. These indicators can be calculated by means of historic observations. The literature shows that the relative theoretical improvement potential of an intra-day forecast compared to a forecast on D-1 is in the range of 30% to 40% maximum[7] which is also confirmed on actual observation shown in Table 14. This can be used to justify a percentage of 35% of the day-ahead forecast error balanced by BRPs, assuming BRPs access the flexibility means. However, with improving liquidity on intra-day markets, it is assumed that BRPs can adapt their portfolio in function of this forecast update. Note however that with increasing renewable capacity, these forecast errors, generally expressed in percentage, require increasing volumes of flexibility, generally expressed in power.

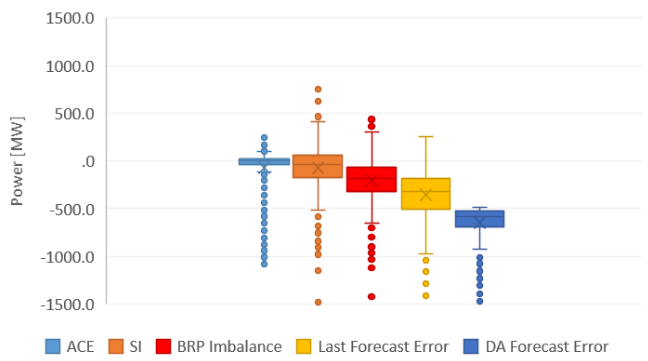
Table 14 : forecast error statistics for year 2018 and 2019 (Elia forecast tools)

2018 - 2019	Mean Absolute Error Day-ahead	Mean Absolute Error Last Forecast	Intra-day forecast Im-provement
offshore	8,4%	6,3 %	34,4%
onshore	4,0%	2,8 %	31,4%
photovoltaics	1,9%	1,3%	32,4%

More difficult it becomes when dealing with unpredicted variations, and in particular large variations which have the most impact on the larger LFC block imbalances relevant for reserve dimensioning. The analyses of DTU already shows that there are positive correlations between the forecast errors and the BRP imbalances.

An analysis has been conducted comparing the LFC block imbalances and imbalances of BRPs with offshore generation in their portfolio during the 1% periods in 2018 and 2019 with highest up- and downward day-ahead forecast errors (excluding storm periods). The distribution of these capacities are depicted in Figure 24 where it is confirmed that part of the day ahead forecast errors are indeed covered by the BRPs.

[7] Projet TradeWind :**www.trade-wind.eu** et « Balancing and Intraday Market Design: Options for Wind Integration », F. Borggrefe, K. Neuhoff ; CPI ; 2010



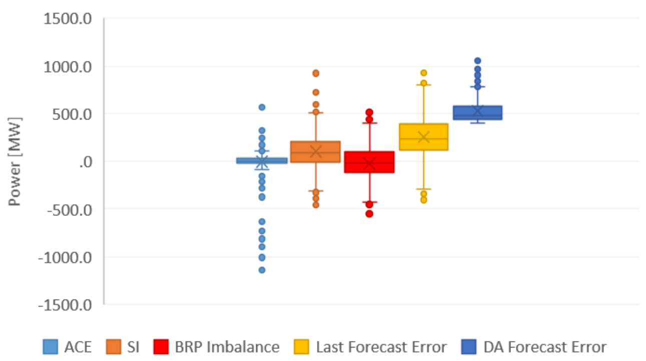


Figure 24: box plots representing the distribution of system indicators during the largest shortage day-ahead forecast error (left) and largest excess day-ahead forecast errors (right)

During these periods, the LFC block imbalances, offshore BRP imbalances and the Last Forecast error are now expressed as percentage of the day-ahead forecast error and analyzed in Table 15. It is shown that on average large part of the day-ahead forecast errors is covered by BRPs and only a small part is translated into a LFC block imbalance, i.e. 17% to upward and 25% for downward. Nevertheless, when looking at the 99% percentile, we can see periods where the LFC block imbalance is equal or even larger as the day-ahead forecast error, both for up- as downward direction.

Table 15: average and percentiles during the largest shortage day-ahead forecast error (left) and largest excess day-ahead forecast errors (right)

PERCENTILE	**ACE**	**SI**	**BRP Imb.**	**LF FE**
SHORTAGE				
Average	10%	17%	33%	54%
P99	100%	100%	100%	100%
P90	39%	49%	74%	100%
P75	6%	25%	49%	80%
EXCESS				
Average	6%	25%	12%	50%
P99	57%	100%	74%	100%
P90	20%	65%	40%	97%
P75	6%	39%	19%	80%

The 90% percentile for example reveals that only 49% of the day-ahead forecast error translates into an LFC block imbalance, and 74% in the offshore BRPs portfolio imbalances. It is assumed that for offshore predictions, an assumption that BRPs can cover 50% of the offshore day-ahead prediction errors might be more suitable for a reference case as the 35% discussed above and therefore considered as a worst case. Additionally, a best case will be investigated where the BRP ability to balance offshore prediction errors amount up to 65%, taking into account all system evolutions contributing to system flexibility and BRPs abilities and incentives to balance, as for instance :

- Shorter market resolutions such as 15' minutes in day-ahead and intra-day may increase the ability of BRPs with limited flexibility in their portfolio to balance their portfolio.
- Imbalance settlement impacts the incentive for BRPs to balance their portfolio. Specific measures are implemented to further fortify this incentive (e.g. a factor alpha) reinforcing the LFC block imbalance prices in case of large deviations, see Section 6.2.2)) or tools allowing BRPs to have better estimations of positions and optimize their portfolio (e.g. a tool to estimate the DSO-infeed of individual BRPs). Elia will continue to investigate ways to incentivize and facilitate BRPs to balance their portfolio.
- More and more new flexibility providers enter the system (see also Section 6.3.1). The adequacy and flexibility study of 2019 shows that sufficient flexibility is expected to be installed in the system to deal with fast variations but that it will not be available when needed. Specific reservation mechanisms for BRPs or TSOs remain necessary. As these will contribute to the BRPs' flexibility to balance their portfolio.

Note that a similar analysis are conducted but particularly during storm events (10/3/2019 + 9-15-16-23/2/2020) and the 1% highest up- and downward hourly ramping events of the offshore generation in 2018 – 19 (Table 16). These will be used as starting point for the scenarios in the analyses of these particular events in Section 5.

Table 16: average and percentiles during storm events as from 2019 (left) and largest 1 hour generation ramping events in 2018-19 (right)

	STORM				RAMPING			
PERCENTILE	**ACE**	**SI**	**BRP Imb.**	**LF FE**	**ACE**	**SI**	**BRP Imb.**	**LF FE**
SHORTAGE								
Average	14%	25%	20%	84%	22%	42%	61%	66%
P99	100%	100%	100%	100%	100%	100%	100%	100%
P90	54%	100%	100%	100%	100%	100%	100%	100%
P75	14%	48%	15%	100%	25%	87%	100%	100%
EXCESS								
Average	15%	38%	25%	33%	18%	41%	31%	67%
P99	100%	100%	100%	100%	100%	100%	100%	100%
P90	55%	100%	100%	100%	78%	100%	100%	100%
P75	16%	87%	40%	60%	19%	93%	61%	100%

4.2.3. Variable renewable forecast tool performance

Future forecast improvements are assumed to show a minor average cumulative improvement factor of 1% in the reference and best case, i.e. the same value as used and justified in the flexibility study. However, as there is large uncertainty on the further evolution of these forecast tools, this value is set at 0% in the worst case. Note that for offshore, the values of offshore provided by DTU are used without any additional forecast improvement corrections.

4.3. Results

4.3.1. CENTRAL scenario

Figure 25 shows the results of the evolution of the average FRR needs with and without the 2nd wave of offshore. It should be clear that these are projections based on the current methodology specified in the LFC block operational agreement and that the final FRR needs will be determined on daily basis taking into account the performance of the market concerning balancing their portfolio.

It can be seen that the upward FRR needs are expected to remain stable at 1039 MW, at least until 2023, determined by the dimensioning incident (DET N-1), in this case the largest nuclear power plant. After the nuclear phase out, the probabilistic method (PROB99) is expected to take over a predominant role in determining the FRR needs increasing the needs to 1104 MW in 2026 and even 1246 MW in 2028. Note that without the 2nd wave of offshore, these values would be respectively 22 MW and 123 MW lower. The increasing trend towards 2028 without the 2nd wave of offshore is explained by the variability of solar and onshore wind power.

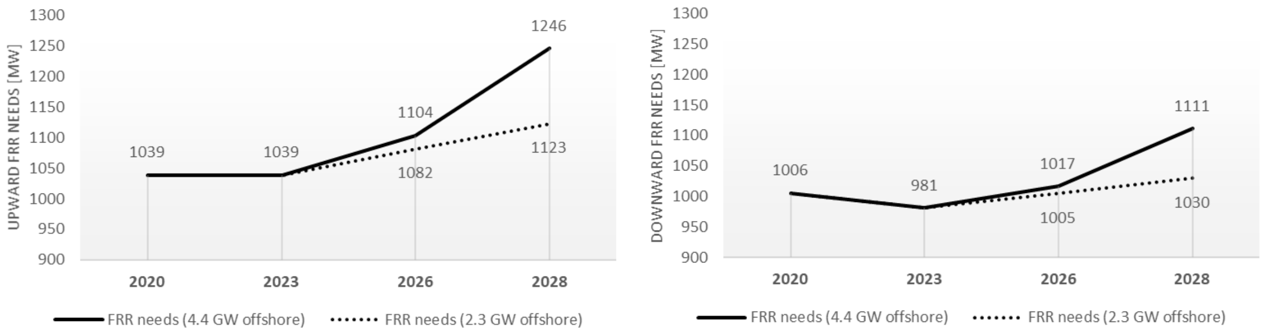


Figure 25: Evolution of the FRR needs with and without 2nd wave of offshore generation capacity

For downward FRR needs, it is observed that the average FRR needs would be reduced between 2020 and 2023. This is explained as Nemo Link is today playing a predominant role in the downward FRR needs as it almost always scheduled in export. As Nemo Link is expected to find itself more frequently in import status during and after the nuclear phase out, this explains why the average FRR needs are expected to be reduced from 1006 MW towards 981 MW in 2023. Note that due to the further increase of renewable generation, the average FRR needs increase up to 1017 MW and 1111 MW. Note that without the 2nd wave of offshore, these would be respectively 12 MW and 81 MW lower. The increasing trend towards 2028 without the 2nd wave of offshore is mainly explained by the variability of solar and onshore wind power. Also note that in general, the FRR needs are lower as on the upward side due to the absence of forced outage risks of thermal generation units.

Figure 26 gives a more detailed look in the evolutions by showing the box plots for the three methodologies determining the FRR need. These box plots represent the 25%, 50% (median) and 75% percentile as the borders of the box, as well as the average represented by the cross. The extending vertically lines indicate the variability outside the upper and lower quartiles, and any point outside those lines or whiskers is considered an outlier and depicted as dots.

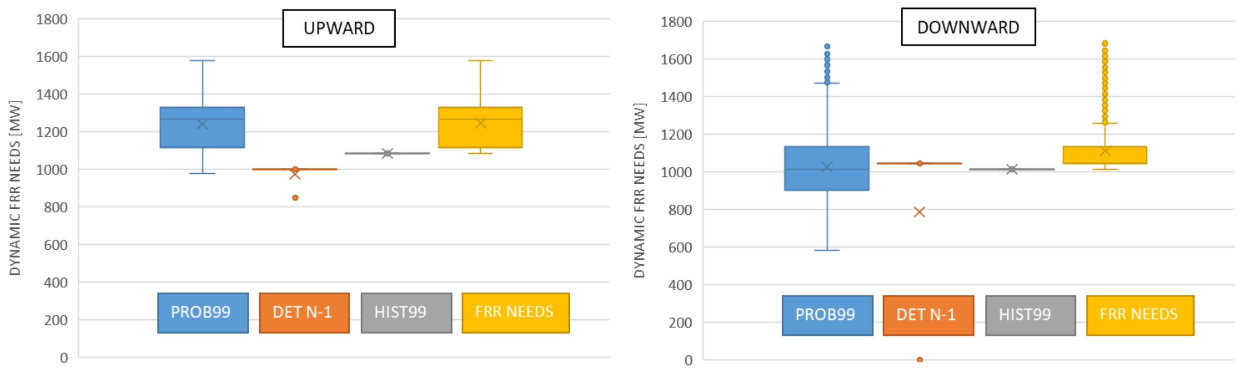


Figure 26: box plots of the FRR needs results and the methodology components (PROB99, DET N-1, HIST99) in 2028

This representation provides quiet some interesting insights for 2028. For **upward**, it shows that the probabilistic method is expected to show large dynamic variations between 1000 MW and 1600 MW. Also note that in contrast to today, the dimensioning incident (i.e. Nemo Link when not expected to be scheduled in export or the largest thermal power plant) does not impact the final result anymore as this remains lower as the result of the legal threshold (HIST99) set at around 1085 MW. This also implies that the reductions of the dynamic FRR needs are also floored at 1085 MW. For **downward**, it shows that the probabilistic results show even larger variations with FRR needs going down to 600 MW which is explained by the lower outage risks compared to upward dimensioning. Again, the legal minimum threshold floors the downward reductions at 1015 MW. In addition, the DET N-1 can still determine the results when Nemo Link is in export, i.e. 1046 MW.

Figure 27 shows the evolution of this dynamic potential from 2020 to 2023 and 2026. It is shown that the dynamics of the PROB99 method increases, as well for up- as downward FRR needs. However, it is also observed that the upward FRR needs will remain to be determined most of the time by the dimensioning incident, i.e. the nuclear units until the phase out before 2026.

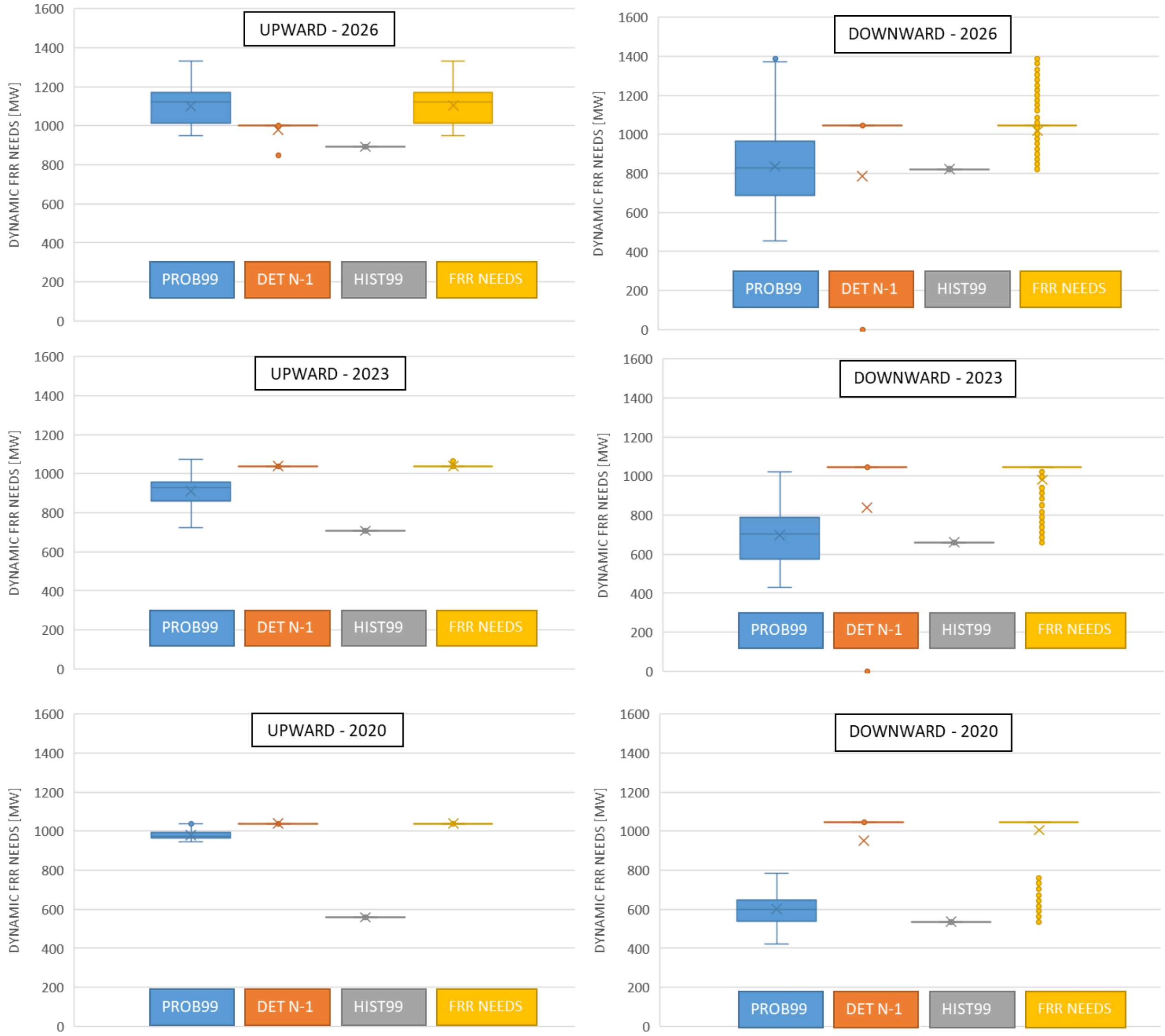


Figure 27: box plots of the FRR needs results and the methodology components (PROB99, DET N-1, HIST99) in 2020, 2023, 2026

4.3.2. Market performance sensitivities

Figure 28 shows the expected impact of the market performance sensitivities on the FRR needs. It is shown that in a worst case, without further forecast improvements for the incremental installed capacity, LFC block imbalance quality improvements, while assuming a low performance of BRPs managing their portfolio imbalances, upward FRR needs can increase to 1175 MW in 2026 and 1466 MW in 2028. Similar for the downward where FRR needs increase to 1061 MW in 2026 and 1340 MW in 2028.

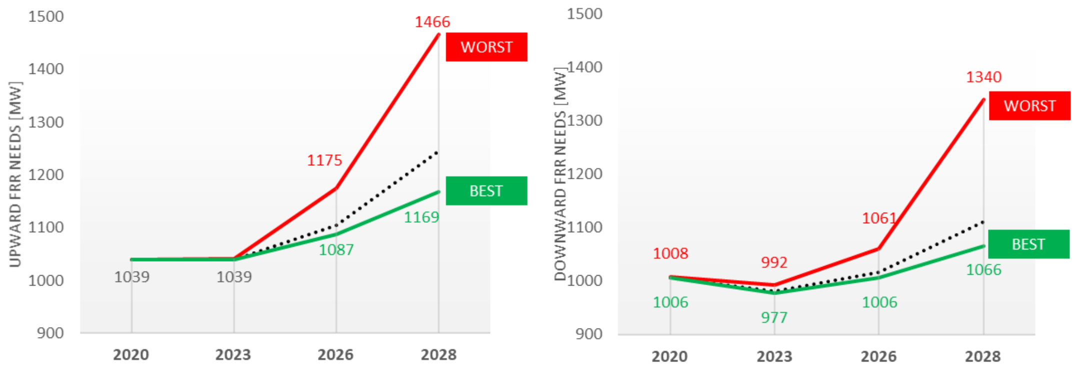


Figure 28: results of the worst case (WORST) and best case (BEST) market performance scenario's

In the other direction, when assuming that forecast improvements and BRP LFC block imbalance improvements are maintained, and that BRPs managing offshore wind generation have a high performance in balancing their portfolio, upward FRR needs can decrease to 1087 MW in 2026 and 1169 MW in 2028. Similar for the downward where FRR needs increase to 1006 MW in 2026 and 1066 MW in 2028.

These analyses confirm that market performance has an important impact on the final FRR needs. A worst versus best case show that the effect can make a difference of almost 300 MW in both directions.

4.3.3. System evolution scenarios

Figure 29 shows the expected impact of the system evolution scenario's H-RES and N-PRO on the FRR needs assuming the reference case. It is shown that a scenario with more onshore and solar renewable generation (H-RES) is expected to increase upward FRR needs towards 2026 and 2028 to 1171 MW and 1382 MW. A similar trend is observed in the downward results where FRR needs are expected to increase to 1072 MW and 1249 MW, respectively. This is can easily be explained by the additional variability and prediction errors of other renewable energy sources such as onshore wind and solar power also have a significant impact on the reserve capacity requirements.

The nuclear prolongation scenario where two large nuclear generation units of 1 GW are prolonged impacts only the upward FRR needs through the outage risk of such a unit. The effect compared to the reference case is mainly observed in 2026, and the effect disappears towards 2028 in light of higher prediction risk of renewables.

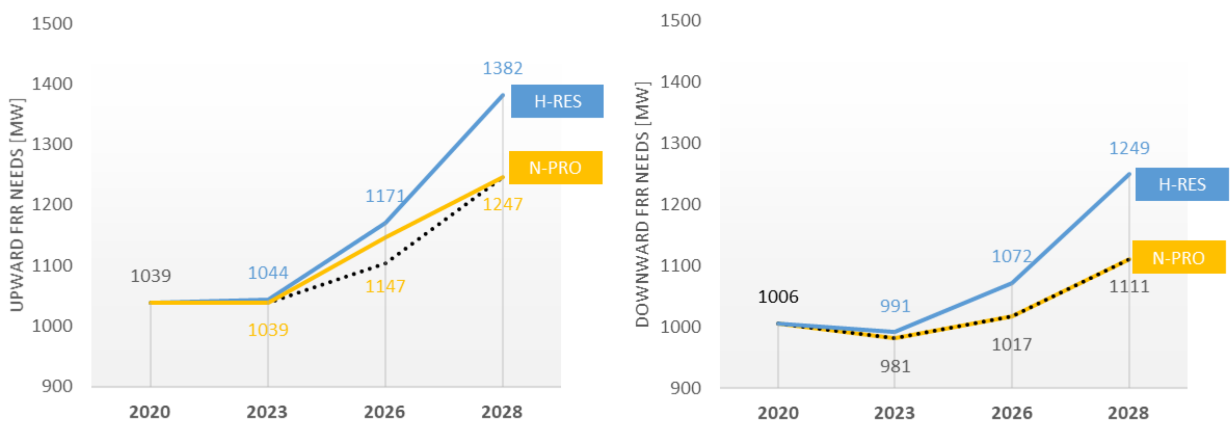


Figure 29: results of the high renewable (H-RES) or nuclear prolongation (N-PRO) system evolution scenario's

Figure 30 shows the expected impact of the S-UNITS and 4.0 GW scenario on the FRR needs in the reference case. It is shown that a scenario where the nuclear units are replaced with smaller units (or at least with units with a lower common-mode failure, i.e. not losing instantaneously all power during a failure) is expected to reduce upward FRR needs towards 2026 and 2028 to 1041 MW and 1196 MW. This is therefore expected to reduce the FRR needs towards 2028 with around 50 MW.

A scenario where the maximum offshore installed capacity in 2028 is reduced to 4.0 GW instead of 4.4 GW results in a small reduction of the up- and downward FRR needs to respectively 1207 MW and 1190 MW in 2028.

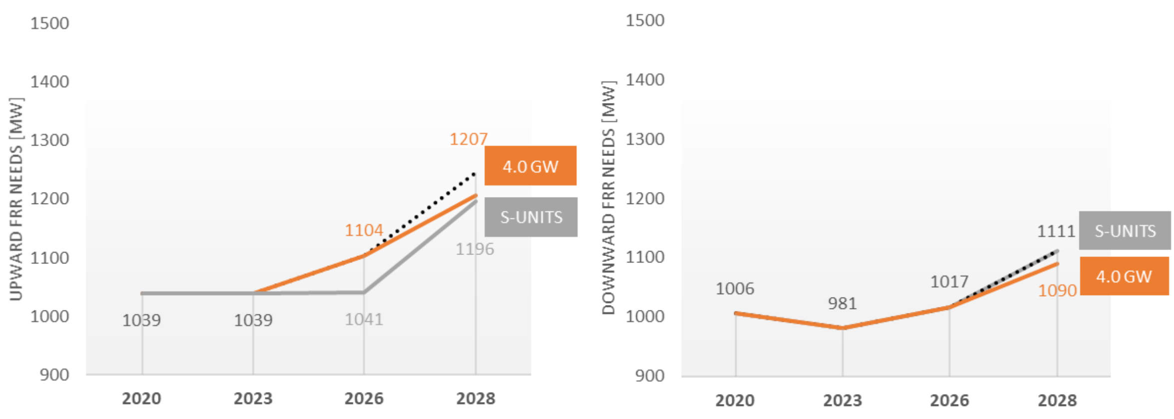


Figure 30: results of the small units (S-UNITS) or 4.0 GW offshore (4.0 GW) scenario's

4.3.4. Ratio aFRR and mFRR

It is already explained that the scope of this study is on the FRR needs as the methodology to dimension the aFRR needs is currently being reviewed in another study. Nevertheless, some preliminary projections are given based on the current methodology. These merely serve to have an idea of the order of magnitude and the future trend of the aFRR needs and mFRR needs (which is the difference between the FRR needs and the aFRR needs).

Figure 31 shows a rough estimation of the aFRR (symmetric, i.e. same capacity in up- and downward direction) and mFRR needs (different up- and downward capacity). An increasing trend is expected towards the future where the aFRR needs may increase up to 177 MW towards 2028. Note that the values represent the results for the reference case in the CENTRAL scenario but it is uncertain that the market performance improvement parameters remain valid for aFRR dimensioning as BRPs may face larger technical challenges to balance their portfolio within 15' while the imbalance settlement period is fixed at 15'.

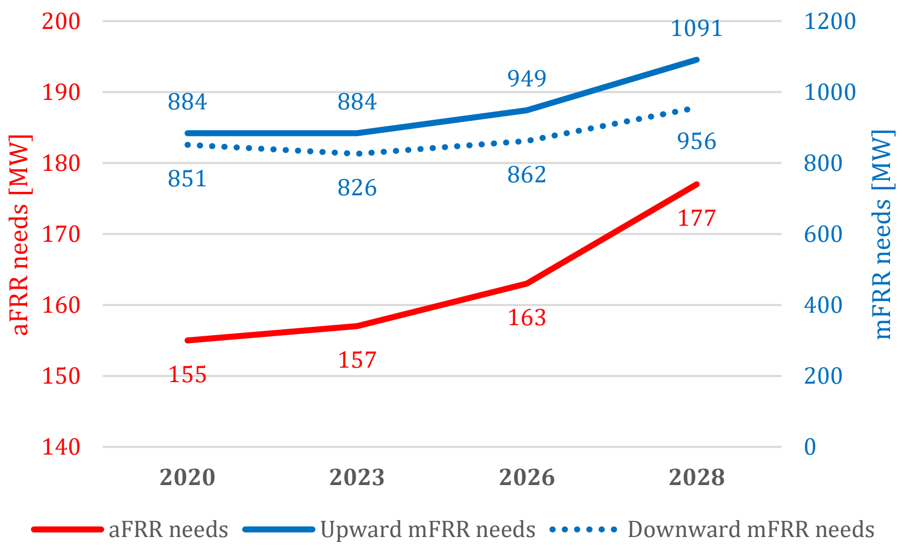


Figure 31: projection of the aFRR / mFRR needs towards 2028

5. Real-time system operation

5.1. Summary of the key outcomes

This Section aims to evaluate the real-time impact of the 2nd wave of offshore generation covering an increase of the installed capacity from 2.3 GW to a maximum of 4.4 GW. The assessment takes into consideration, the outcomes and assumptions derived from previous Sections in term of possible offshore generation and relevant technology impact, as well as the system evolution with respect to flexibility and reserve capacity.

The section 5.2 provides an overview of the general approach and the details related to the selection of events from the simulations conducted by DTU. The methodology in term of impact evaluation and validation criteria is introduced and discussed in the section 5.3 while all the underlying assumptions, sensitivities and evaluated scenarios are detailed in the section 5.4. Finally, the results of the simulation events are presented and analyzed in the section 5.5 taking into consideration the defined scenarios and sensitivities.

Violation of criteria

The analysis identified several scenarios where the validation criteria are violated for both the 3.0 GW and 4.4 GW installed capacity scenarios. In case these violations would materialize (depending on the evolution of our assumptions in the future) they would require the definition and the implementation of mitigation measures as covered in Section 6.

- Considering ramping events, the scenarios of large ramping of volumes of 3.0 GW or more resulted in violations for both upward and downward events.
- The 4.4 GW installed capacity presents unquestionably the highest level of violations both in terms of duration (long lasting violations), and severity (high imbalances comparing to the 3.0 GW installed capacity).
- On the other hand, for the 3.0 GW scenario, violations have been observed only in the case of worst case BRP scenarios.

Sensitivities for ramping events

In term of sensitivities, the best case BRP scenarios have a significant positive impact on solving all violations except for the most extreme upward and downward ramping events (4.0 GW, 3.5 GW, 3.0 GW, -3.5 GW and -3.0 GW) where the positive effect is insufficient. Even though these events remain limited in term of probability, they will be very challenging to mitigate, particularly for downward ramping events. In fact, these violations persisted even taking into consideration the most optimistic cases of FRR reserves availability.
On the other hand, sensitivity analysis of faster activation of reserves based on a combination of scheduled and direct mFRR activation showed some improvements. The analyzed ramping events results hint to the need to accommodate faster flexibility needs either by leveraging enhanced coverage of BRPs or through dedicated fast reserves.

Sensitivities for storm events

Considering storm events, similarly the 4.4 GW installed capacity cases presented larger violation impact compared with the 3.0 GW one as they are typically of longer duration on top of the higher impacted volumes in terms of cut-off.

In terms of sensitivities, the best case BRP scenario showed the most effective impact as no more violation was observed. The observed violations could also be mitigated when increasing the available FRR volume, except for the violations that are typically observed during the cut-off phase with high gradient.
On the other hand, in such events faster combined activation of reserves (direct and scheduled activation) showed relatively limited impact in solving violations as improvement are only limited to the ramping phase of the storm where FRR activation might lag to cover fast gradient imbalance.

As a general conclusion, the analysis on real-time impact has shown violations of the validation criteria defined. The results are sensitive towards the assumptions that had to be made to cover the uncertainties related the future functioning of the market and the technological developments by the time the 2nd wave offshore capacity will be commissioned. In order to be able to assure the robustness of the system and considering the sensitivity on the assumptions, effective mitigations measures need to be prepared in the event the existing mechanisms and the ongoing initiatives to improve the system imbalance would not be sufficient. These measures are described in Section 6.

5.2. Selection of events

DTU has provided simulations for different scenarios of installed offshore wind parks in the Belgian North Sea. These simulations include the power output of existing and new offshore wind power parks in resolutions up to 5 minutes for 37 years.

For each scenario of installed offshore capacity, DTU has defined the storm and most extreme ramping events which were observed during the 37 years of simulation data, as well as the frequency of each of these events. A specific selection of ramping and storm events for scenario 3.0 GW and 4.4 GW has been used by Elia as input for the analysis on real-time system operation.

5.2.1. Extreme ramping events

In the context of the analysis, extreme ramping events are defined as a high increase (or decrease) in power output over a limited time period. The analysis focuses on three types of ramping events, as provided by DTU, namely:

1. 5 minute ramping events
2. 15 minute ramping events
3. 60 minute ramping events

For each of these events, the maximum power deviation has been defined using steps of 500 MW as well as their occurrence. Also the days in the simulation on which these events occurred were defined. Based on this information, specific events have been selected representing the different cases to be analyzed. For these events, the simulated data series have been provided with a resolution of 1 minute in order to perform a detailed analysis.

The analysis mainly focuses on 60 minute ramping events due to the fact that these events include all observed 5 and 15 minute ramping events. The highest increase and decrease in volumes have been observed only during 60 min ramping events. The different values used for an installed capacity of 3.0 GW and 4.4 GW are displayed in the below Tables.

3,0 GW installed offshore generation	
Ramp up / down [MW]	**Duration [min]**
2500	60
2000	60
1500	60
-1500	60
-2000	60
-2500	60

Table 17: Scenarios for 3.0 GW offshore installed capacity

4,4 GW installed offshore generation	
Ramp up / down [MW]	**Duration [min]**
4000	60
3500	60
3000	60
2500	60
2000	60
1500	60
-1500	60
-2000	60
-2500	60
-3000	60
-3500	60

Table 18 : Scenarios for 4.4 GW offshore installed capacity

The analysis was performed only using data sets taking into account wind turbines of technology type 'TECH B' for 2^{nd} wave of offshore generation. This was done to limit the already high amount of simulations to be performed. Using TECH A or a mix of both technologies would lead to a slightly lower impact on the system imbalance.

5.2.2. Storm events

Storm events can lead to a decrease of power output due to the wind speed exceeding the cut-out speed of wind turbines. A storm event is characterized by a cut-out phase followed by a relative stable power output and cut-in phase. The analysis mainly focuses on extreme storm events with very high wind speeds resulting in a high or total cut-out of the offshore wind parks.

For each of these events, the maximum power deviation during the storm event, as well as the days in the simulation on which they occurred were used. Based on this information, specific events have been selected representing the different cases to be analyzed. For these events, the simulated data series have been provided with a resolution of 1 minute in order to perform a detailed analysis.

The analysis was performed only using data sets taking into account wind turbines of technology type 'TECH B' with high wind technology scenarios 'HWS Deep' for 2^{nd} wave of offshore wind parks. This was done to limit the already high amount of simulations to be performed. The expected impact of the other technologies assumed is the following:

- The impact of Tech A / Tech B on the storms is limited to the fact that the hub height of Tech B is about 30m more than for Tech A, so TECH B is slightly more subject to be exposed to high winds.

- On the contrary, the “Deep” technology shows a smoother shutdown profile in case of storm events, reducing the speed and amplitude of the cut-off phase compared to the “Moderate” and the “25 direct cut-off” technologies.
- With the 25m/s direct cut-off technology in the 4.4 GW scenarios, > 2 GW down-ramps in 15 minutes time are seen in the simulations a few times over the 37 years, while this is not the case with HWS technologies. This would be particularly challenging to manage for the BRPs and for Elia.

The analysis of DTU on the behavior of storm events has displayed possible extreme 15 min upward ramping events during cut-in phase of a storm event, due to a simultaneous, fast increase in power output of all wind turbines. This issue is already addressed today by the possibility for Elia to coordinate the cut-in phase after a storm. Therefore, only cut-out phase of storm events has been considered in the Elia analysis.

5.3. Methodology

A deterministic analysis has been used to determine whether or not a specific event can be considered as acceptable in terms of impact on real-time system operations. The analyses does not take into account any mitigation measures or specific restrictions, however some sensitivity analysis have been performed to display the impact of specific measures.

5.3.1. Simulation model

A specific simulation model has been created to simulate the reaction of BRPs and Elia using assumptions on flexibility that will be activated by BRPs and by Elia to compensate the observed ramping or storm event. The simulation model considers two variables, representing the balancing energy and BRP reaction, used for compensation of concerned ramping or storm event which are challenging to forecast. These cases and the associated approach are shown on Figure 32.

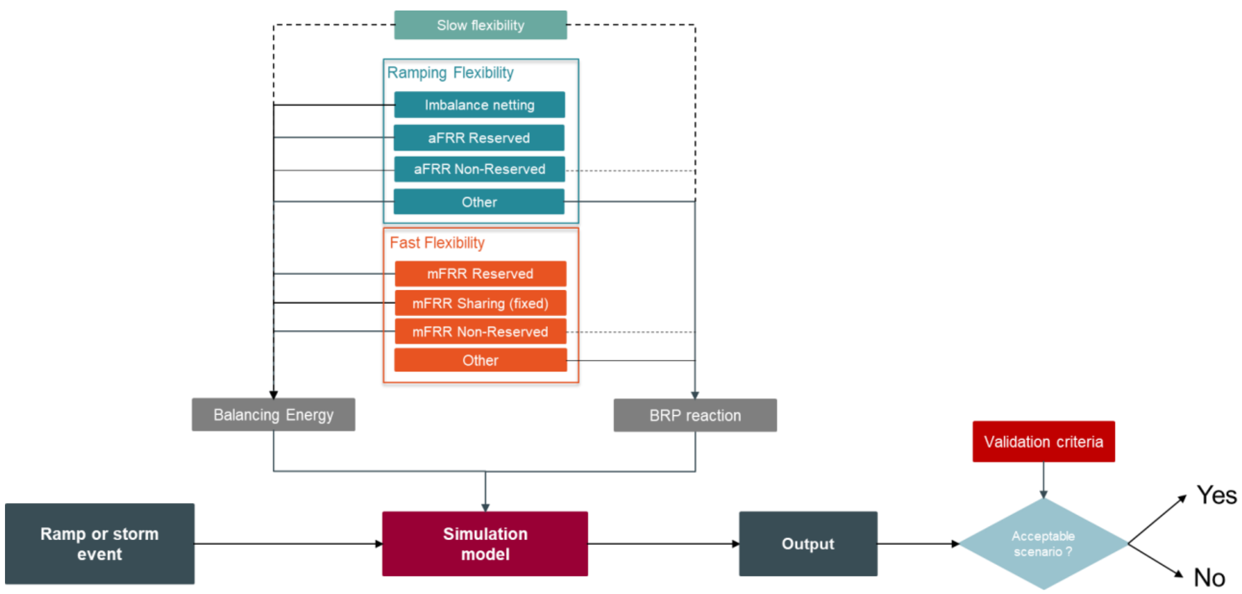


Figure 32: Schematical representation of the simulation model used for analysis of impact on real-time system operations

The simulation model results in two outputs:

- 'System Imbalance'[8] defined as the difference between the change in power output of the offshore wind parks and reaction of offshore BRPs
- 'Area Control Error'[9] defined as the difference between System Imbalance and Net Regulating Volume, representing the Balancing Energy activated by the TSO.

5.3.2. Validation criteria

5.3.2.1. SOGL articles

In order to validate whether a simulated ramping or storm event can be considered as acceptable in terms of impact on real-time system operations, specific validation criteria on the maximum acceptable imbalances and duration of these imbalances have been defined in the context of this analysis. These validation criteria are based on requirements of SOGL, as well as operational agreements between TSOs. These will be used to assess the severity of outcomes and thus the potential need in term of mitigation measures.

Article 18.2 of SOGL indicates that the Continental Europe Synchronous Area goes into alert state if the frequency deviation is higher than 50 mHz for 15 minutes or higher than 100 mHz for 5 minutes.

Article 18.3 of SOGL states that the Continental Europe Synchronous Area will go into emergency state if the frequency deviation exceeds 200 mHz.

In order to convert this into an imbalance criteria for the Elia control area, we considered at Elia should not be responsible for more than 25% of the deviation. This ratio is significant comparing to the size of the Belgian LFC block, which is somehow reflected by the ratio of the FCR obligation of Belgium which is around 80 MW of the total volume of 3000 MW needed for the overall continental synchronous area. The 25% thresholds is reflected as well in the Article 152.13 of SOGL, which indicates that a participation of more than 25% to the total deviation for more than 30 consecutive minutes needs to be avoided. The validation criteria are defined to avoid the occurrence of such events.

With the above principles and considering a regulating power factor of the continental system of 30000 MW / Hz (this means that a deviation of 3000 MW leads to a frequency deviation of 0.1 Hz or 100 mHz), the frequency deviation from SOGL can be converted into an imbalance of the Elia control zone.

This means that:

[8] Also referred to as LFC block imbalances

[9] Also referred to as FRCE (Frequency Restoration Control Error)

- A frequency deviation higher than 50 mHz for 15 minutes would correspond to an imbalance higher than 375 MW for 15 minutes, which should be assimilated to an alert state. A frequency deviation higher than 100 mHz for 5 minutes becomes an imbalance higher than 750 MW for 5 minutes, which should as well be assimilated to an alert state.
- A frequency deviation higher than 200 mHz (for any duration) becomes an imbalance higher than 1500 MW, which should be assimilated to an emergency state
- Coming back to Article 152.13 of SOGL, we can also state that the imbalance of the Elia control area cannot exceed 25% of the reference incident of continental Europe (which is 3000 MW) for 30 minutes. So the imbalance of the Elia control zone cannot exceed 750 MW for 30 minutes.

5.3.2.2. Status indicator

Following the above SOGL articles, we differentiate cases in function of the severity which is done by means of a color indication as in the EAS (Emergency Awareness System):

a) **Green zone** : Normal state

It represents the normal situations and all acceptable cases.

b) **Yellow zone** : Reference to Alert state

The yellow zone represents a violation of the criteria and implies that the extraordinary procedure for frequency deviation would be launched, which requires all TSOs to take action to reduce the frequency deviation.

c) **Red zone** : Reference to Emergency state

The red represents a violation of the criteria and could trigger load shedding (depending on the observed frequency at that time).

These criteria are used in the following analyze sections and they can be illustrated by the hereunder Figure 33 :

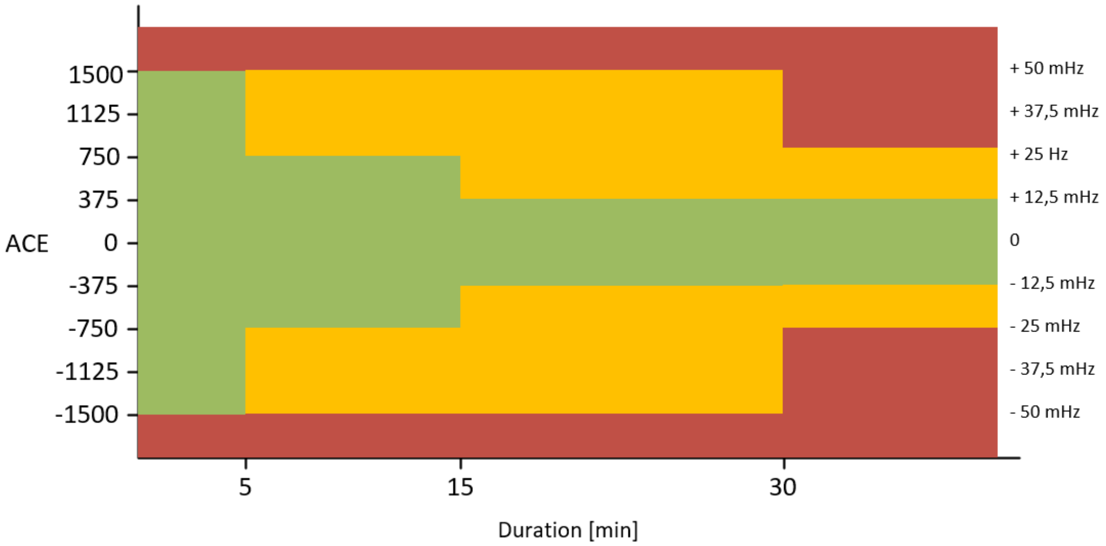


Figure 33: Validation criteria visualized considering time domain

5.4. Scenario's & assumptions

This section provides more details on the different scenario's and assumptions which have been used in the simulation model to perform the analyses. Considering the installed capacity scenarios, the scenario 4.0 GW has not been analyzed, as the ramping and storm events impact does not present substantial difference comparing to the 4.4 GW scenario thus the outcomes and conclusions remain similar and valid for both levels.

5.4.1. Starting situation

The analysis focuses on a mapping of the consequences of Belgian offshore wind generation during extreme ramping and storm events on real-time system operation. The model simulates individually each specific event, taking into account the reaction of BRPs and TSO to the event. The starting offshore production value of the event, at time 'zero', is defined by the data available for this timestamp. All other possible events or actions that could occur simultaneously are supposed not be correlated and hence are not taken into account.

Each event starts at time 'zero' for which all balancing parameters are considered normal, namely:

- Frequency = 50 Hz
- Area Control Error = 0
- System Imbalance = 0
- Net Regulating volume = 0 MW

The dimensioned FRR requirements are considered to be fully available.

5.4.2. Flexibility in the system

As explained in Section 3, the total flexibility needs in the system can be divided into three categories: Ramping flexibility, Fast Flexibility and Slow Flexibility.
The simulation model does not take into account each type of flexibility separately, but uses a simplified approach were the available flexibility in the system is represented by use of different scenarios for BRP reaction and FRR availability. For each event, the analysis thus makes a distinction between the flexibility needs that were covered by the market players, and the needs covered by the TSO through contracted and non-contracted balancing energy. It is important in that context to mention that the intrinsic potential of flexibility cannot be double counted on both sides. As per the analogy of communicating vessels concept, caution should be kept in not considering very optimistic scenario in term of BRP reaction and in the same time foreseeing large available volumes of restoration reserves.

5.4.2.1. BRP ability to cover imbalances during extreme events

As discussed in section 4.2.2, a quantitative analysis of historical BRP reaction during normal and extreme conditions has been performed. For evaluating the reserve capacity needs, this analysis is used as a basis for defining the scenarios related to the ability of BRPs to cover imbalances in the future configuration.
For extreme events, it appeared to be much more challenging to proceed that way for following reasons:

- There is a limited return of experience on storm events with significant installed capacity. Moreover, the BRP reactions improved significantly between 2019 and 2020 (storm procedure, α, BRP learning curve,…) and all 4 storm events in 2020 occurred during the weekend
- There are some more samples for ramping events, but the challenge lies in the way to define a ramping event, the associated BRP coverage during the event and the time necessary to recover the imbalance.

Therefore, as a basis to define the scenarios of BRPs' ability to cover imbalances during extreme events, a case-by-case analysis was performed on the most relevant historical storm and ramping events. The results of all evaluated events are available in annex B and some specific cases are highlighted below. For each graph:

- The blue curves indicate forecasts and power production. The scale used is on the left axis
- The green curves indicate the imbalances and the ACE value. The scale is on the right axis.
- The "imbalance net" curve corresponds to the sum of the imbalances of the BRPs having at least one offshore wind park in their portfolio, while the "system imbalance" curve represents the total system imbalance.

It's important to note that, for the most extreme historical events that have been analyzed, it appears that the total system imbalance is driven by the BRPs having at least one offshore wind park in their portfolio. Reactive balancing from other BRPs does not seem to significantly influence the system imbalance.

Examples of ramping events are shown in Figure 34 and Figure 35. These examples show a quite low reaction of the BRPs, especially when the ramping event is not forecasted. On the 14th of October 2019, a system imbalance of almost -1000 MW is observed for a wind power production drop of about 1200MW. Other examples from the full analysis show a better coverage by the BRPs, reaching about 65% in the best cases. In general, it appears that 1 to 1.5 hours are necessary for the BRPs to recover their position.

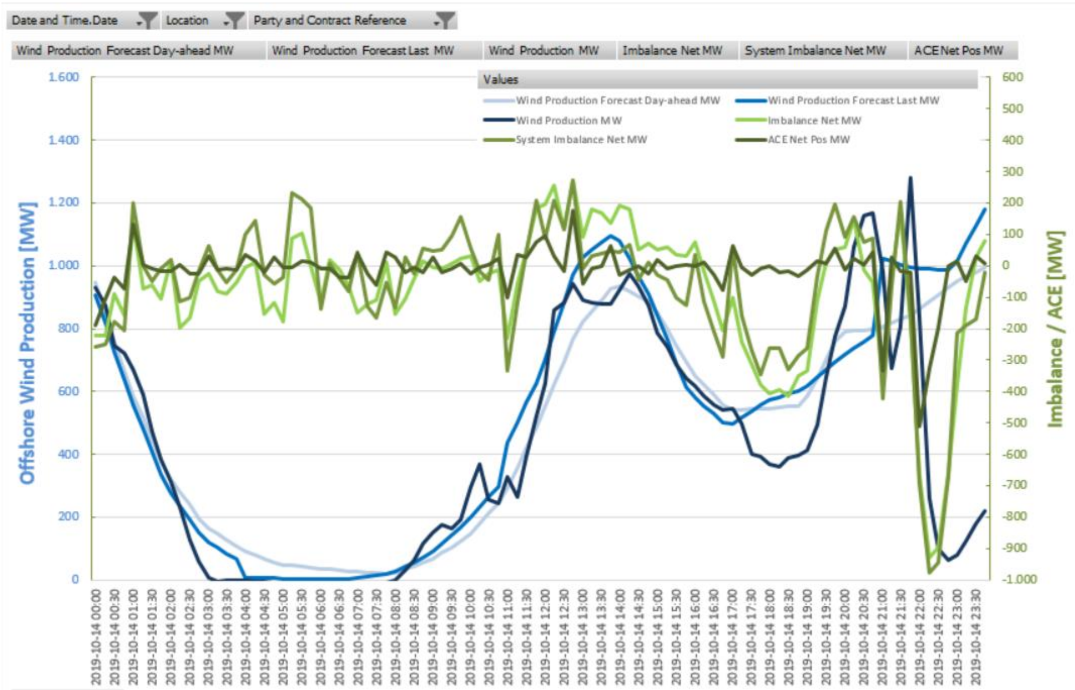


Figure 34: BRP reaction during ramping event on the 14th of October 2019

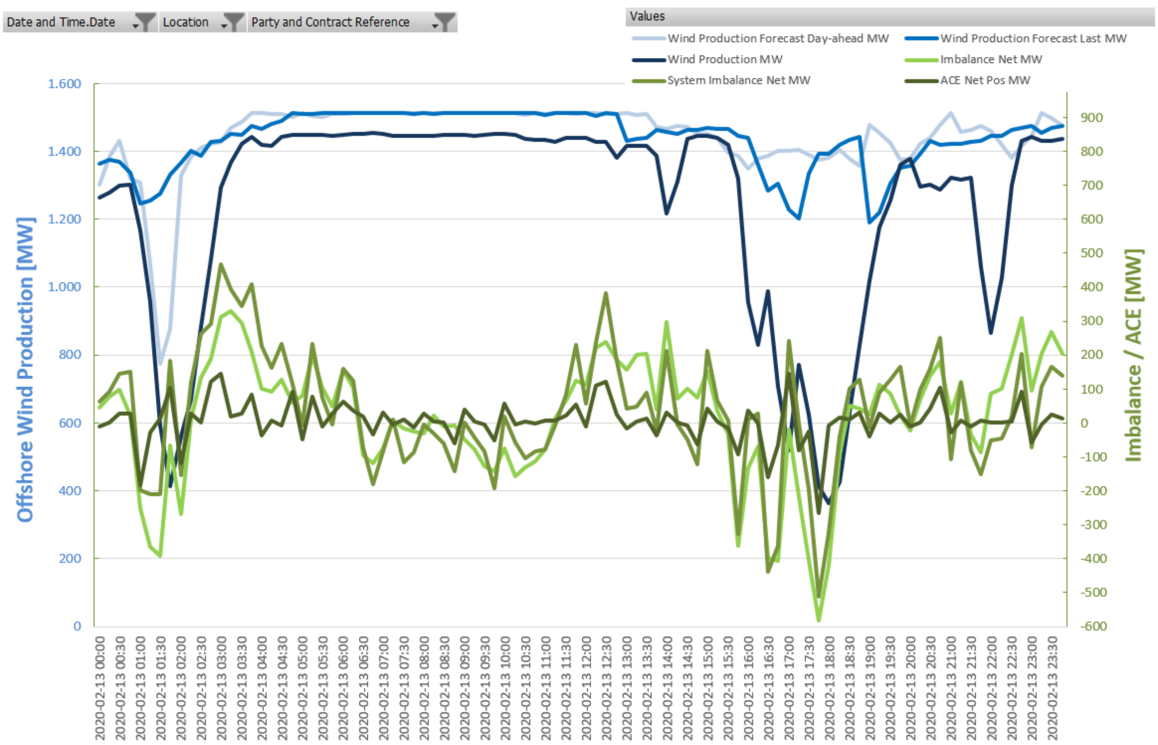


Figure 35: BRP reaction during ramping event on the 13th of February 2020

The historical behavior is used as a basis for defining the scenarios. However, the estimated effect of foreseen initiatives towards the future needs to be taken into account. On the other hand, some significant ramping events appear not to be forecasted at all. With extended capacity, a same percentage of BRP coverage requires increasing volumes of flexibility when expressed in power. For example, a 50% coverage of a 3.0 GW ramping down event means that the BRPs will cover 1.5GW when the wind production reaches its minimum value. So even if the value of 50% could appear to be conservative, there are currently no situations requiring such an extensive and fast reaction from BRPs.

Examples of storm events are shown in Figure 36 and Figure 37. Both storm events were forecasted in Day-ahead.

The storm event on the 10th of March 2019 resulted in an imbalance of about -700MW, for a partially forecasted drop in wind power production of about 1000MW, indicating a coverage by BRPs of 30%. It has to be noted that this event occurred before the go-live of the storm process and of the revised alpha. About 2 hours were needed for the BRPs to recover their position, helped by the cut-in phase of the storm.

The BRP reaction during the Ciara storm in February 2020 showed a very significant improvement, with a minimum coverage of 80% of the power drop. It's to be noted that for this case, we specifically looked at the imbalance of the offshore BRPs, as it is compensated by an initial positive system imbalance and not by reactive balancing from the non-offshore BRPs.

The go-live of the storm process (even if the fallback process didn't have to be activated) and of the revised alpha that occurred shortly before this date is supposed to have had a positive effect.

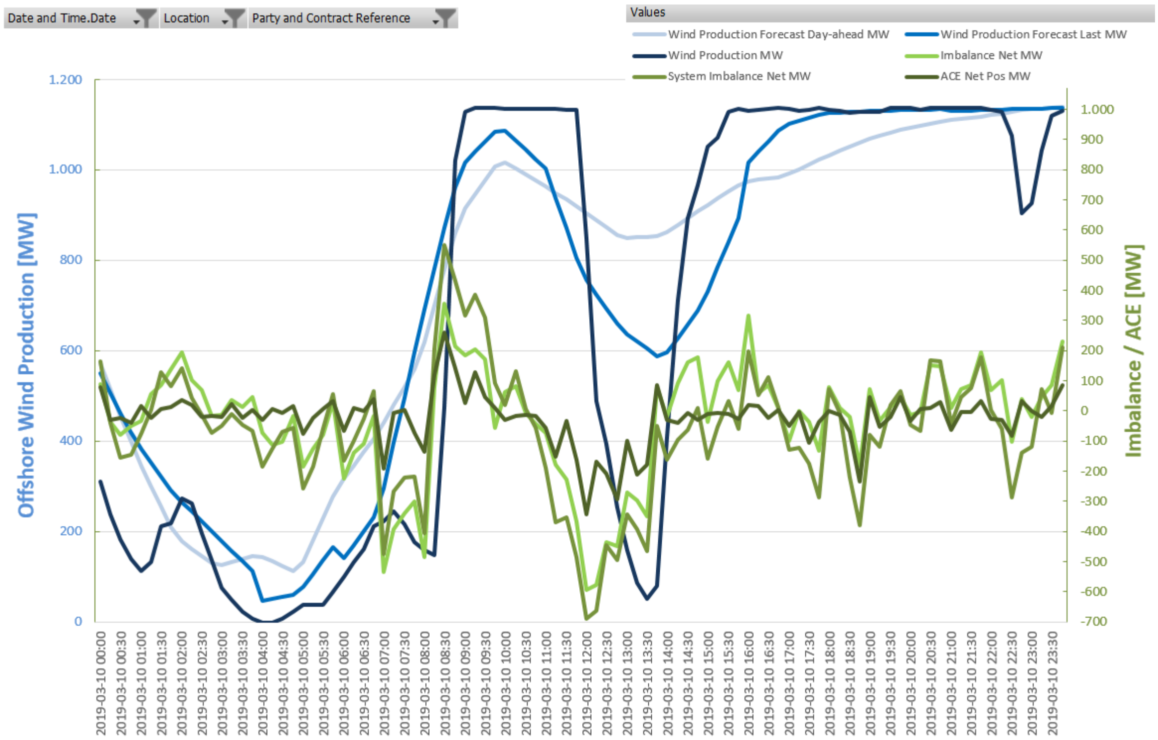


Figure 36: BRP reaction during the storm event on the 10th of March 2019

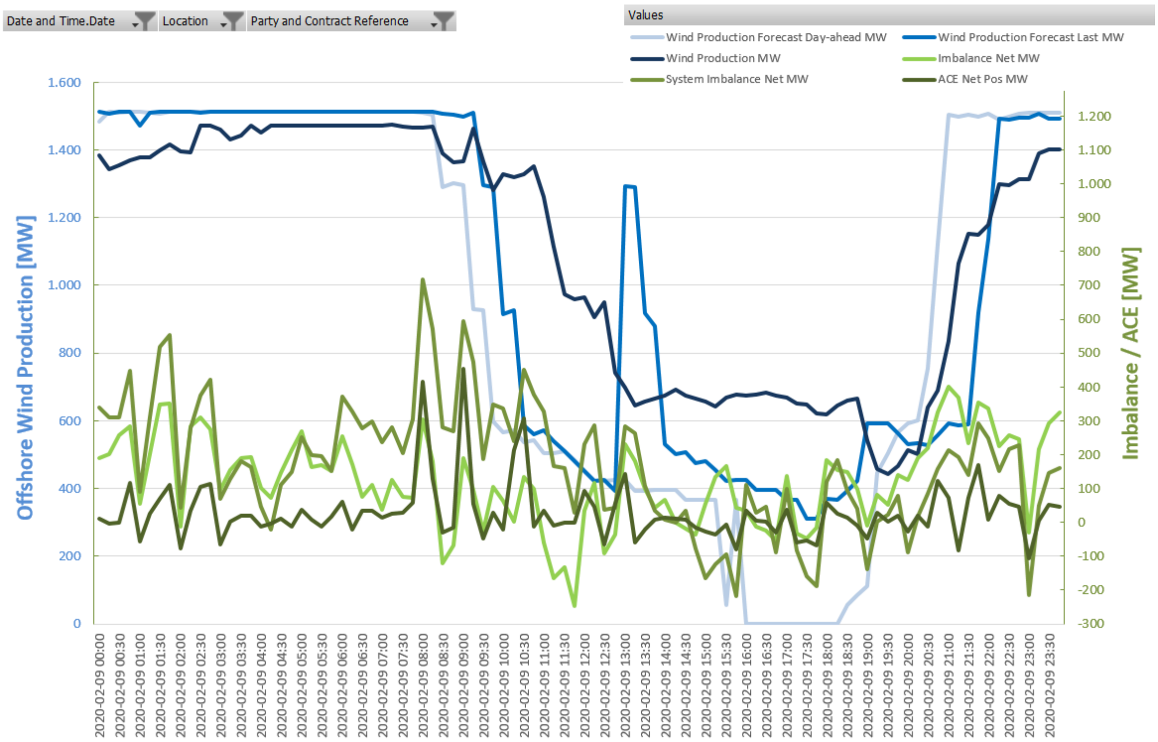


Figure 37: BRP reaction during the Ciara storm event on the 9th of February 2019

On these bases, a best and worst case scenario have been developed for storm and ramping events separately, as displayed in Table 19.

	Ramping event		Storm event	
	Coverage	Full recovery time	Coverage	Full recovery time
Best case	50%	60 minutes	80%	60 minutes
Worst case	30%	120 minutes	40%	120 minutes

Table 19: Scenarios for BRP reaction

These scenarios are considered to take into account all types of flexibility means that are available and can be activated by BRPs to cope with storm and ramping events.

Considering the ongoing evolutions that could have an impact on the ability of BRPs to cover imbalances (alpha, storm process, offshore capacity increase until 2.3 GW,…), these assumptions will have to be reviewed before the tendering phase, on the basis of the return of experience in the years 2020 to 2022.

Each scenario for BRP reaction has been modelled using the same principles, as mentioned below:

1. No reaction during the first 5 minutes of the event
2. Gradual increase to coverage level with steps of 2.5% per minute
3. Steady coverage level until the end of the ramping event or cut-out phase of the storm event

4. Linear increase of coverage to full recovery, based on full recovery time, after the respective event

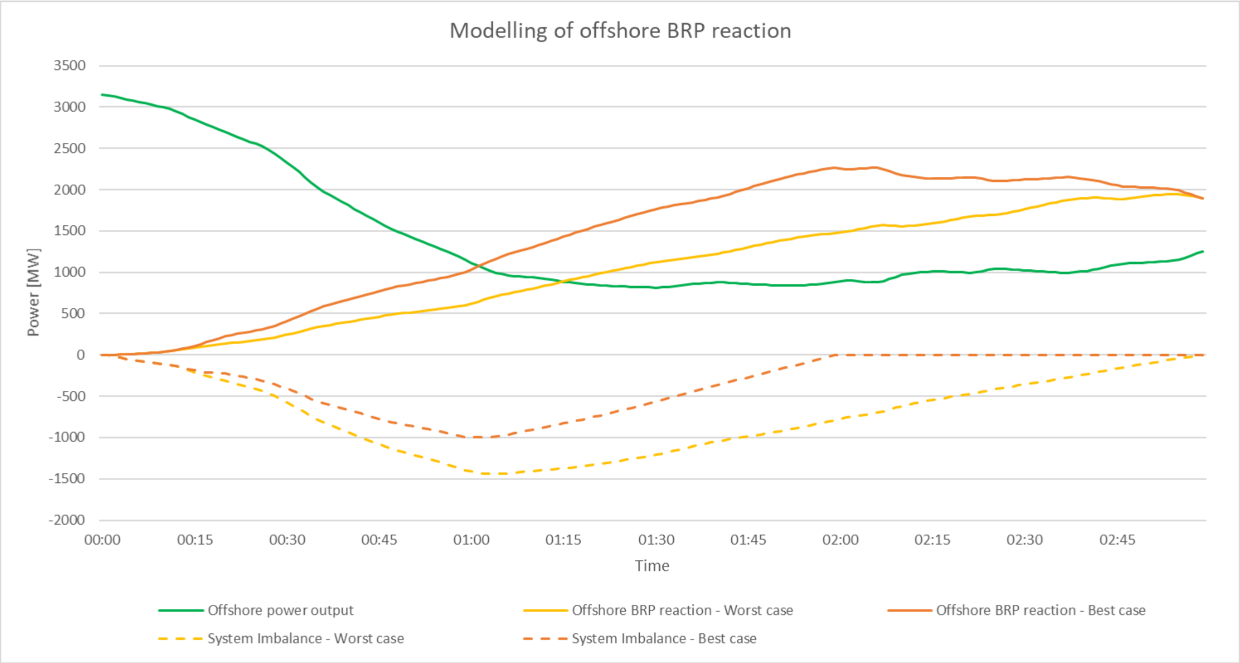


Figure 38: Visual representation of modelling of BRP reaction for a 3.5 GW downwards ramping event in 60 minutes

5.4.2.2. Frequency Restoration Reserves

One of the main objectives for the TSO is to ensure system security, including the balance of the system, in line with the European network guidelines while incentivizing the market players to balance their portfolios as much as possible. In order to be able to ensure this task the TSO contracts reserve capacity.

The reserve capacity contracted by the TSO can be seen as a subset of the fast and ramping flexibility. When establishing a link between the reserve capacity types and the flexibility types, we can say that the fast flexibility will contain the future FRR (aFRR + mFRR) needs, for which the mFRR FAT (Full Activation Time) considered is 15.0 minutes, which is in line with the existing requirements as well as these for the MARI[10] platform.

The existing criteria used by TSO operators for activation of mFRR during these types of events was modeled.

[10] Manually Activated Reserves Initiative (MARI) is the European implementation project for the creation of the European mFRR platform

The ramping flexibility will contain the future aFRR which has a FAT of 5.0 minutes, which is in line with the requirements for the PICASSO[11] platform. For the activation of aFRR, a modelling of the existing LFC controller was included in the simulation model.

Note that the FCR falls outside of this study as it is not its purpose to solve individual LFC block imbalances.

The total FRR requirements which are dimensioned by Elia can be covered by contracted balancing capacity, but also with non-contracted balancing energy bids and reserve sharing agreement. However, as the latter two categories are not guaranteed, these can only be accounted to cover the FRR requirements if assessed to be guaranteed in periods where they are needed. For this reason, case 1 of the Table 20 starts from the current situation where the dimensioned upward FRR needs in 2026 and 2028 are entirely covered with balancing capacity (with 163 / 177 MW of aFRR balancing capacity and 891 MW / 1019 MW of mFRR balancing capacity for respectively 2026 and 2028), except from 50 MW of reserve sharing with neighboring TSOs.

However, as previously discussed, fast flexibility may be available in the system which can be offered to the TSO as aFRR and mFRR non-contracted balancing energy bids within the Elia control area and within the European platforms taking into account the available cross-zonal capacity. The other three cases foresee an increasing FRR volume of 1500, 2000 and 2500 MW, by assuming non-contracted mFRR or additional mFRR sharing volumes, as displayed below.

UP							
		Total FRR	**aFRR**	**Contracted mFRR**	**mFRR Sharing**	**Non-contracted mFRR & additional mFRR Sharing**
3,0 GW (2026)	Case 1	1104	163	891	50	0
	Case 2	1500				396
	Case 3	2000				896
	Case 4	2500				1396
4,4 GW (2028)	Case 1	1246	177	1019	50	0
	Case 2	1500				254
	Case 3	2000				754
	Case 4	2500				1254

Table 20: Different sensitivities of total FRR in the upward direction containing the estimated volumes for each type of reserve

Similar to the upward FRR, the available downward FRR starts from a case which contains the minimum volume for FRR which is equal to the dimensioned reserve capacity of aFRR and mFRR as determined by Elia for 2026 and 2028. However, it is assumed that, as today, this capacity can be covered solely with mFRR non-contracted balancing energy bids and mFRR reserve sharing on top of the aFRR balancing capacity. Again, the other three cases assume additional FRR means of 1500, 2000 and 2500 MW, by assuming additional non-contracted mFRR or mFRR sharing volumes, as displayed in Table 21, in line with expectations on fast flexibility in the system.

[11] Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) is the European implementation project for the creation of the European aFRR platform

DOWN					
		Total FRR	aFRR	mFRR (non-contracted + sharing)	Additional non-contracted mFRR & mFRR sharing
3,0 GW (2026)	Case 1	1017	163	854	0
	Case 2	1500			483
	Case 3	2000			983
	Case 4	2500			1483
4,4 GW (2028)	Case 1	1111	177	934	0
	Case 2	1500			389
	Case 3	2000			889
	Case 4	2500			1389

Table 21: Different sensitivities of total FRR in the downward direction containing the estimated volumes for each type of reserve

Additionally, a sensitivity analysis is conducted by adding additional volumes of aFRR to selected cases. This is related to the ramping flexibility in the system as discussed previously. As it is observed that available capacity may depend strongly on the available ATC will have to be shared between the different reserves, it is assumed that additional available aFRR is compensated by a reduction of the non-contracted mFRR for that scenario. Likewise, IGCC12 potential can be considered taken into account in this sensitivity analysis for ramping flexibility.

As reference case, only use of Scheduled Activations was considered. Next to the scheduled activations, the operators of the TSO have indeed the possibility to also perform direct activations of mFRR reserves as soon as they observe significant and persistent system imbalance. The main advantage of a direct activation is that the reaction time for the activation is lower, resulting in a lower delay in activation of mFRR. In order to analyze the impact of this type of activations, the same events are simulated using a combination of scheduled and direct activation.

Currently, direct activations are mainly used for events where the volume of 'lost power' is well known, for example a forced outage of a large power plant. However, in case of a power deviation of offshore wind generation, an increasing system imbalance will occur for which the operator cannot estimate in advance the maximum deviation as well as the duration of the ramping event. For these cases, using the direct activation is very difficult. Therefore, the simulations using a combination of scheduled and direct activation should be considered as a sensitivity analysis instead of a reference scenario based on scheduled activation. Elia took the initiative to start a project with as objective to evaluate whether prediction algorithms of System Imbalance would be reliable in extreme events. Such prediction tool exists already by other TSOs. If this project should prove that such prediction gives reliable results, Direct Activations could be more used in the future to activate mFRR reserves, while avoiding possible over-compensation that might occur and has been observed in the simulation and reported for example for the upward ramping events with 3.0 GW installed capacity (see Annex B).

[12] IGCC is a cooperation between TSOs which deals exclusively with Imbalance Netting for automatic Frequency Restoration Reserves (i.e. to avoid counter activation of aFRR in different Control Areas) under residual ATC constraints at the borders to provide operational security.

5.5. Results

The resulting Area Control Error (ACE) of each event is compared to the different thresholds used as validation criteria (see Section 5.3.2) for which the continuous duration above each threshold is monitored. The threshold, together with the continuous duration, defines whether an event can be considered as acceptable without any mitigation measure. The results are shown in the tables by means of a color indication as explained in the Section on the validation criteria. As a reminder, the thresholds used are:

- Threshold 1 (T1) = 375 MW
- Threshold 2 (T2) = 750 MW
- Threshold 3 (T3) = 1500 MW

The 2nd wave of offshore wind generation is divided into two phases, namely an increase to maximum 3.0 GW offshore wind generation in the first phase and to a maximum of 4.4 GW in the 2nd phase. As the ramping and storm events may have a different impact for each phase, separate analyses were performed.
The structure of the results is the following:

- Installed capacity of 3.0 GW
    - Ramping events
        - Upward ramping events with scheduled activations of mFRR means
        - Downward ramping events with scheduled activations of mFRR means
        - Upward ramping events, combination of scheduled and direct activation of mFRR means
        - Downward ramping events, combination of scheduled and direct activation of mFRR means
    - Storm events
        - Scheduled activations of mFRR means
        - Combination of scheduled and direct activation of mFRR means
- Installed capacity of 4.4 GW: same structure.

In each section, the results are shown for all selected events with the sensitivities on the BRP Scenario (Best or Worst Case) and on the FRR contracted volume.
Due to the high amount of simulations performed, the detailed results and corresponding analyses are available in annex B. The main conclusions are gathered in Section 5.6 and an example of detailed result is shown in Table 22 below. This example refers to downward ramping events in 60 minutes for 4.4 GW offshore generation with scheduled activation of mFRR means.

Table 22: Results for simulated downward ramping events in 60 minutes for 4.4 GW offshore generation

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
Deep-3p5GW	Worst Scenario	1246	375	71	750	46	1500	0
Deep-3p5GW	Worst Scenario	1500	375	61	750	29	1500	0
Deep-3p5GW	Worst Scenario	2000	375	36	750	22	1500	0
Deep-3p5GW	Worst Scenario	2500	375	36	750	22	1500	0
Deep-3p5GW	Best Scenario	1246	375	28	750	0	1500	0
Deep-3p5GW	Best Scenario	1500	375	27	750	0	1500	0
Deep-3p5GW	Best Scenario	2000	375	30	750	0	1500	0
Deep-3p5GW	Best Scenario	2500	375	30	750	0	1500	0
Deep-3p0GW	Worst Scenario	1246	375	56	750	7	1500	0
Deep-3p0GW	Worst Scenario	1500	375	44	750	0	1500	0
Deep-3p0GW	Worst Scenario	2000	375	36	750	0	1500	0
Deep-3p0GW	Worst Scenario	2500	375	36	750	0	1500	0
Deep-3p0GW	Best Scenario	1246	375	19	750	0	1500	0
Deep-3p0GW	Best Scenario	1500	375	19	750	0	1500	0
Deep-3p0GW	Best Scenario	2000	375	19	750	0	1500	0
Deep-3p0GW	Best Scenario	2500	375	19	750	0	1500	0
Deep-2p5GW	Worst Scenario	1246	375	53	750	0	1500	0
Deep-2p5GW	Worst Scenario	1500	375	34	750	0	1500	0
Deep-2p5GW	Worst Scenario	2000	375	34	750	0	1500	0
Deep-2p5GW	Worst Scenario	2500	375	34	750	0	1500	0
Deep-2p5GW	Best Scenario	1246	375	0	750	0	1500	0
Deep-2p5GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-2p5GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-2p5GW	Best Scenario	2500	375	0	750	0	1500	0
Deep-2p0GW	Worst Scenario	1246	375	20	750	0	1500	0
Deep-2p0GW	Worst Scenario	1500	375	20	750	0	1500	0
Deep-2p0GW	Worst Scenario	2000	375	20	750	0	1500	0
Deep-2p0GW	Worst Scenario	2500	375	20	750	0	1500	0
Deep-2p0GW	Best Scenario	1246	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1246	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1246	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2500	375	0	750	0	1500	0

5.6. Conclusions

In order to evaluate the possible impact on real-time operation, a set of simulations have been conducted using historical ramping and storms events while taking into consideration several sensitivities including reserve activations (scheduled/slower ⬄ direct/faster activation), available FRR means (4 different levels from low to high) and possible BRP reaction (worst case ⬄ best case) scenarios. This means that for different levels of installed capacity 32 different combinations have been simulated.

The analysis identified several combinations (both for the 3.0 GW and the 4.4 GW installed capacity) where the validation criteria to ensure secure system operations are violated. If we look at the high level summary of the results in Figure 39 we can see that, for the most pessimistic combination of assumptions, large imbalances of long duration occur both for the 3.0 GW and the 4.4 GW installed capacity. Looking at the combination of the most optimistic assumptions for all parameters the results looks much better, however, for the 4.4 GW installed capacity violations still occur:

Figure 39: Summary of the most important events with a view on the sensitivities of assumptions

It's fair to say that neither the most pessimistic nor the most optimistic cases are the most likely to happen, the truth will be somewhere in between those 32 different possible combinations depending on the BRP reaction, liquidity and speed of reaction. The most important insights of our simulations show that:

1) It's not a surprise that the scenarios with 4.4 GW installed capacity represent the highest risks, not only in terms of largest imbalances, but also in terms of long-lasting deviations.

2) The BRP behavior has a significant impact on most of the results, even though it might sound like kicking in an open door, all positive measures taken by BRPs can only reduce the need for Elia to fall back on mitigation measures in the future.[13]

3) It is confirmed that in case these violations would materialize (depending on the evolution of the assumptions in the future) they will require mitigation measures. Either to ensure that the optimistic assumptions can be guaranteed and/or to close the remaining gap.

4) Storm events, specifically for the 4.4 GW scenarios, resulted in extremely long and large violations in the scenario with the pessimistic assumptions, specific attention is required to mitigate this storm risk.

Based on the analysis of the results and their sensitivities, effective mitigation measures can be found by

- reducing the origin of the deviations at the source and/or
- increasing the availability of liquidity (in Belgium or abroad) and/or
- increasing the reaction speed for the activation of said liquidity (by BRPs and/or Elia).

[13] It is important to remind, that beyond dedicated mitigation measures, Elia will pursue further improvements as the availability of good price signals, balancing market integration, market facilitation and stimulation of reactive balancing.

6. Mitigation measures

6.1. Introduction

The present Section provides a preliminary list of mitigation measures considered to address the challenges identified in the previous sections. The measures described primarily intend to mitigate the risk of violation of the validation criteria identified in section 5 (impact on real-time system operation). However, most of them are also expected to have a positive impact on the absolute average value of the system imbalance, mitigating the increase of reserve capacity needs as analyzed in Section 4.

The update of the flexibility needs performed in Section 3 allowed to confirm that, if the system is adequate, sufficient flexibility will be installed in the system, but it will not always be operationally available when needed. This means that upfront reservations (by BRPs or Elia) will remain necessary. Therefore, the measures described focus on the objective to have the flexibility available in the system at the moment it's needed.

As explained earlier in this report, the MOG II System Integration project aims at identifying the necessary mitigation measures before the tendering phase of the new concessions, to provide as much clarity as possible to the potential candidates before their financial closure. A consequence of this approach is that assumptions need to be defined to cover the uncertainties on the future functioning of the market and the technological developments by the time the 2nd wave offshore capacity will be commissioned. It is to be noted that, while some uncertainties will remain until the construction of the parks (technologies, installed capacity,…) or even after commissioning (flexibility in the system, BRPs' reaction in extreme conditions,…), additional elements will be available that may lead to a re-evaluation of the assumptions considered in this study before starting the tendering phase. The following examples can be noted:

- The updated Adequacy and flexibility study (available latest by June 2021)
- The return of experience with 2.3 GW installed capacity and the storm procedure, which went live beginning of 2020
- The return of experience of the modification of the alpha component, which is applicable since the 1st of January 2020

In addition, ongoing initiatives are expected to result in additional means at disposal of BRPs to effectively balance their portfolio.

For these reasons, the objective of the project in 2020 is establish a list of mitigation measures as exhaustive as reasonably possible and to evaluate the effectiveness of these measures in addressing the challenges identified in Sections 4 and 5 as well as their impact for the BRPs and for the future wind parks. Taking into account the uncertainties remaining at this stage, Elia is willing to engage in a discussion with stakeholders on the assumptions defined in the study, the methodologies used and the impact of the mitigation measures.

For the present version of the report, a preliminary list of mitigation measures has been considered. The link with previous Sections is made in a qualitative way. On the basis of the feedback from the public consultation, the mitigation measures will be further assessed, developed and, when possible, their effect will be quantified. A second public consultation is planned in October 2020 to collect formal feedback on the results of these analyses. However, Elia considers stakeholders' feedback on the preliminary list of potential measures when responding on this first consultation as a highly valuable, and even necessary input to be able to make in October a mature proposal of mitigation measures. Any additional proposal for mitigation by the stakeholders during this first consultation would be also much welcomed by Elia.

Table 23 below gives an overview of the challenges identified in Section 5 and the mitigation measures considered to address each of these challenges. The considered mitigation measures are further explained in the next sections of the document.

Table 23: overview of mitigation measures and their impact on the challenges identified

	Mitigation measures	**Up ramps**	**Down ramps**	**Storm cut-out**	**Storm cut-in**	**Reserve needs**
Existing mechanisms	Current storm procedure			X		
	Alpha	X	X	X	X	X
	Coordination of cut-in phase				X	
Actions to be investigated by Elia	Incentivize reactions to real-time prices	X	X	X	X	X
	mFRR activation triggers	X	X	X	X	
	Enhanced forecast functionalities	X	X	X	X	X
Measures implying constraints for wind parks and / or concerned BRPs	High wind speed technologies			X		
	Preventive curtailment of wind parks			X		
	Ramping rate limitation	X	(X)	(X)	X	
	Coverage of imbalances by BRPs	X	X	X	X	X

(X): apply only in cases of voluntary production decrease.

Important remark: the new mitigation measures should either not be applied to the existing parks, either not have a direct financial impact on the existing parks.

6.2. Existing mechanisms that contribute to balancing in extreme conditions

6.2.1. Current storm procedure

The storm procedure[14] applicable until 2.3 GW installed capacity went life on the 15th of January 2020. As explained in the introduction of the present report (cf. Section 1), the solution implemented might not be sufficient to cover additional capacity that would be installed after 2020. This is confirmed by the analyses performed in the present study (cf. Section 5).

The existing storm procedure is however supposed to be maintained for the existing parks and extended to the future parks, as it provides following advantages:

- The storm alerts support the BRPs to anticipate the impact of a forecasted storm
- The storm process initiates an exchange of information between the offshore BRPs and Elia, allowing Elia to evaluate the residual risk, on the basis of the volume that is not covered by the offshore BRPs
- The fallback process provides a framework to timely start slow-start units that would not be running while they would be needed for balancing purposes when the storm occurs

6.2.2. Alpha

The modified alpha component of the imbalance price is an effective measure to incentivize BRPs to stay in balance and/or to contribute to the system's balance. This is the case for ramping and storm events, but also in normal conditions, which leads to a positive impact on the reserve capacity needs as well.

The expected impact of the alpha component has been taken into account in the study through the scenarios on BRP's reactions. As the modification of the alpha has been applied recently, the return of experience will be analyzed before the launch of the tenders in order to re-evaluate the assumptions if necessary.

The importance of a well calibrated Alpha may also not be underestimated in the effects of reactive balancing. As allowed by the BRP contract, market parties (in this case other than the offshore BRPs) may deviate from their balance to "help" the system balance. As flexibility and the ability to react to (close to) real time prices penetrates more and more towards retail consumers (enabled by the roll out of smart meters and revised commercial offerings), the potential of reactive balancing is expected to increase towards the future. In the absence of reliable data, assumptions have been made in the quantitative analysis on the (positive) effects of reactive balancing. These assumptions will have to be reviewed before the tendering phase, on the basis of the return of experience in the years 2020 to 2022.

As the analysis clearly showed the importance of good market reaction (both by the concerned BRPs as well as by others through reactive balancing) in managing the system impact of ramping and storm events, Elia will continuously

[14] OFFSHORE INTEGRATION DESIGN NOTE. Elia, 2019. https://www.elia.be › elia-site › role-of-brp › brp-pdf-document-library

aim at improving this market reaction through, if necessary, the further fine-tuning of the Alpha or by studying the opportunity to publish additional forecasts. In this respect, Elia intends to study in 2021, the opportunity to publish a forecast of the upcoming system imbalance.

6.2.3. Coordination of the cut-in phase after a storm

The analysis from DTU clearly demonstrates the need to coordinate the cut-in phase after a storm event (see Figure 12). The provisions in Articles 252 of the Federal Grid Code are translated in the T&C SA and OPA and can be applied to ensure this coordination.

These provisions will also be applicable for the new wind parks to allow Elia to safely ensure coordination of the cut-in phase.

6.3. Measures to be investigated by Elia

6.3.1. Incentivize reactions to real-time prices

Until today, there is no direct link between consumers' behavior in the lower voltage levels and the price signals of the wholesale market or imbalance market. As a result, end-prosumers are currently not able to react in function of high imbalance prices.

In the framework of the initiatives to unlock new energy services for consumers, Elia is putting in place an ecosystem allowing market parties to develop new services for the end-consumer. A dedicated real-time communication layer will route the data from millions of digital meters and connected assets in real time to all parties in the system (including but not limited to the BRPs), enabling end-prosumers to participate in the electricity market, especially in times when the system needs it the most.

In this way, these initiatives are expected to have a positive impact on the availability of reserves, but also on the ability for BRPs to cover imbalances. This is particularly the case in extreme conditions, where the system imbalance is prone to be high, but also in normal conditions, which leads to a positive impact on the reserve capacity needs as well.

6.3.2. mFRR activation decisions in a context of extreme events

As demonstrated in Section 5, some violations of the validation criteria can be solved with a faster reactivity of mFRR means. Therefore, while the existing criteria used by TSO operators for activation of mFRR was used in the reference scenario, a sensitivity analysis was performed where also direct activations were included to cope with extreme variations of wind power.

Currently, direct activations are mainly used for events where the volume of 'lost power' is well known, for example a forced outage of a large power plant. However, in case of a power deviation of offshore wind generation, an increasing system imbalance will occur for which the operator cannot estimate in advance the maximum deviation as well as the duration of the ramping event. This could lead to a risk of over-compensation, as observed in the simulations performed (See Section 5).

For this reason, Elia needs to investigate the feasibility of effectively using direct activations of mFRR to cope with extreme variations of wind power. In this context, the study planned in 2021 to evaluate the possibility of using System Imbalance prediction algorithms is expected to provide relevant input.

6.3.3. Measures related to forecasts

Currently, offshore wind forecasts published by Elia consist of:

- Production forecasts. The forecast range covers a period up to 7 days and is refreshed every hour starting from beginning of June this year. Only the aggregated offshore wind power production is published on Elia's website
- A tailored-made model developed by KMI/IRM generates storm alerts for offshore wind production. The latter includes the forecasted loss of production by wind park

Section 5 has demonstrated the need, when extending capacity beyond the 2.3 GW planned, not only to address imbalances caused by storm events, but also those caused by ramping events. Therefore, Elia proposes to investigate following possible upgrades of the forecasts:

- On top of a large variety of weather data coming from several global weather models, for each relevant localization, current forecast providers mostly use measurements available on ENTSO-E Transparency platform or other open source data on TSOs' sites. Providing, in real-time, the wind speeds measured by the wind turbines from another park (in a relatively close surrounding of the park to be forecasted) at hub height level could potentially increase the quality of the forecasts, especially when more measurements points over a wider area become available, which will be the case with the future parks. The highest expected benefits from this improvement would be for close to real-time forecasts, when cumulated with machine learning algorithms.
- Based on these enhanced close to real-time forecasts, Elia could publish ramping alerts. In parallel, an indication of the expected production loss or gain for each wind park would be individually communicated to the concerned parks and their respective BRPs.
- Elia could also publish a ramping risk indicator in day-ahead, allowing BRPs to better anticipate this risk.

Preliminary discussions have taken place with a forecast provider, but the feasibility as well as the potential benefits from these upgrades will need to be confirmed. Depending on the outcome, this measure could support an improvement of the system imbalance in case of ramping events, but also in normal conditions, which would lead to a positive impact on the reserve capacity needs as well.

It is reminded that, in any case, the forecasts will be published by Elia for indicative purposes. BRPs remain responsible for forecasting the production of the assets in their portfolio and for managing their balancing position.

6.4. Measures implying constraints for wind parks and / or concerned BRPs

6.4.1. High wind speed technologies

High Wind Speed (HWS) technologies allow to smoothen the shutdown profile of the wind park during storm events. While it has been observed in DTU's analyses that HWS technologies for the new parks have a limited impact on fleet-level for one specific extreme storm events (see Section 9.5 of DTU's report), experience with existing parks, simulations performed by DTU and the resulting analyses of Elia have demonstrated they have a positive impact on the frequency and in the vast majority of the cases on the speed of shut-downs.

Table 24 shows the average number of days per year for the different scenarios as simulated by DTU where following conditions are met:

- A max wind speed > 20m/s
- A ramping event > 2GW in 1 hour time or less

Table 24: Average number of days per year with high wind and high ramps

			# of days per year
3.0 GW	Tech A	25 m/s	0.3
		Moderate	0.4
		Deep	0.3
	Tech B	25 m/s	0.3
		Moderate	0.3
		Deep	0.3
4.0 GW	Tech A	25 m/s	2.8
		Moderate	1.5
		Deep	0.5
	Tech B	25 m/s	2.6
		Moderate	1.7
		Deep	0.7
4.4 GW	Tech A	25 m/s	4.5
		Moderate	2.1
		Deep	0.6
	Tech B	25 m/s	5.5
		Moderate	2.5
		Deep	0.8

The table shows that HWS technologies have a positive impact on the ramping down events during days with high wind speed, especially when the installed capacity increases.

It's to be noted that the analyses performed in this study assumes that the "Deep" technology would be installed on all new wind turbines. The other 2 technologies considered (25 m/s direct cut-off and "Moderate type") would lead to additional violations of the validation criteria during storm events. In particular, the DTU analysis has shown that for the regular 25 m/s direct cut-off in the 4.4 GW scenarios, > 2 GW down-ramps in 15 minutes time are seen in the simulations a few times over the 37 years, while this is not the case with HWS technologies. In addition, the “Deep” type shows a reduction of downward ramping events compared to the “Moderate” type.

Finally, it was also observed in DTU’s report that HWS technologies slightly improve forecast errors during high wind speed days.

Considering those results, it appears necessary to impose minimum requirements for the shutdown behavior to the new wind parks. The precise requirements need to be further defined.

6.4.2. Preventive curtailment of wind parks

The analysis performed in Section 5 allowed to draw the following conclusions:

- As only the “worst case” scenario on BRP coverage resulted in violations, there is a need to support appropriate BRP reaction
- In case this would not be sufficient, availability of additional volumes need to be secured upfront
- Considering the amount of volumes needed, the slow start-units that could be activated on the day of the storm in the current storm process might not be sufficient

As the occurrence of storms are usually well forecasted in day ahead, planning to reduce production of the wind parks at that horizon of time would allow the BRP to find the energy necessary to stay in balance.

Systematically remunerate preventive curtailment would imply to socialize costs arising from risks created by the new wind parks. On the other hand, we understand that the future parks need an indication of the impact that non-remunerated preventive curtailment could have on the production estimations.

Therefore, Elia would consider to limit the possibility to preventively curtail wind parks without remuneration to a maximum amount of hours over a given period. The 37 meteorological years simulated by DTU will be used as support to define the cap.

As storms don’t occur equally between different years (see Figure 10), defining the cap on a yearly basis would lead Elia to be sufficiently conservative to cover all events that could reasonably occur during 1 year. When considered retrospectively, the cap would likely be considered as too high on certain years. For this reason, Elia would consider applying the cap over fixed periods of 5 years.

The trigger to preventively curtail wind parks would be based on the storm tool. The decision would be notified before the day-ahead gate closure time, in order to allow the BRP to not commercialize its production in DA, or to make sure that the BRP is able to find in the market the energy necessary to compensate a lack of production, if relevant. A security margin on the starting time of curtailment would be considered to cover cases where storms occur earlier than forecasted. The preventive curtailment would result in an additional incentive for the wind parks to select technologies with favorable storm shut-down behavior, as this behavior is modeled in the storm tool. The flexibility that Elia expects to be able to activate would also be considered in the process.

An order of magnitude of the cap would be 75 equivalent full production hours of preventive curtailment spread over a period of 5 years. This is however a very preliminary figure to be confirmed on the basis of additional statistics to be calculated.

For the sake of clarity, the preventive curtailment would come in addition to the provision from the Royal Decree of the 16th of July 2002 on promotion of renewable energies, stating that, “remuneration of curtailment is not due where the Modular Offshore Grid is scheduled to be unavailable in accordance with the procedures laid down by the grid operator, for the first sixty cumulative hours at full load of unavailability occurring in a calendar year”.

This approach is expected to have a limited financial impact on the future parks for the following reasons:

- The cap is low in comparison with the average annual production hours
- The cap includes hours where the wind park would likely not have been able to produce anyway due to the storm
- The electricity prices on the wholesale market are expected to be low during these periods, limiting the financial loss for the wind parks
- As the precise moment where wind parks start to decrease production due to high winds is difficult to forecast, curtailment will limit the risk for the BRPs to be unbalanced at a moment where the imbalance price is expected to be high

Experience shows that the occurrence of heavy storms are well forecasted, but that it cannot be expected from models that they forecast the exact timing and impact of a storm event. Introducing a conditional remuneration in case of forecast errors (i.e. compensating the curtailment if Elia’s measures are proven inadequate) would very much complicate the process (questions may arise such as what would be an acceptable forecast error margin, what would be the reference price for a compensation, etc.). For this reason, and as the use of a reasonable cap provides warranties to future wind parks as such, this mitigation measure would not include a remuneration in case of errors in Elia’s forecasts.

6.4.3. Ramping rate limitation

Applying a permanent limitation of upward ramping rate would lead to significant loss of production from the wind parks. In addition, current experience with the existing wind parks as well as the time series from DTU simulations have indicated that positive ramping events can occur immediately or shortly after negative ramping events, in which case the ramping rate limitation could prevent the offshore BRP to recover its position as quickly as possible.

However, DTU’s study has shown that, without considering the cut-in phase after storms, positive ramping events of more than 2GW in 1 hour time are expected to occur about 4 days a year on average. For these kind of ramping events, section 5.5 and Annex B shows violations of the validation criteria in some cases. The expected violations increase significantly for higher ramping events, even if those occur less often. For ramping events higher than 3.0 GW, violations are even observed in the simulations with the most optimistic assumptions of BRP coverage.

In addition, there could be some cases where the wind parks voluntarily decide to reduce production, like negative prices, self-curtailment or maintenance. The production decrease resulting from those voluntary actions is expected to be lower than the ramping events resulting from the analysis in Section 2 and evaluated in Section 5, but it could potentially occur very fast.

Therefore, a temporary ramping rate limitation, which would be applied in situations with risks of significant imbalance, seems an effective mitigation measure to keep the ACE under control in these specific cases. The ramping rate limitation would be imposed in line with SOGL Article 137(4)(a):

"All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE[15] target parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:

(a) obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units; …"

The ramping rate limitation would be communicated via a signal sent by Elia to the wind parks, which would have to apply the limitation without undue delay and the latest 1 minute after the signal was sent. The wind parks will have to be equipped to be able to process the signals sent by Elia.

Further analyses are required to define the parameters that would trigger the application of the ramping rate limitation as well as the value of the ramping rate and duration of the limitation. These analyses will be conducted by the 2nd consultation of this project, planned on the 1st of October.

Should these additional analyses lead to the conclusion that triggering ramping rate limitations in real-time is necessary but not sufficient, Elia will consider the possibility to apply ramping rate limitations preventively. These limitations would be triggered by an upgraded forecasting tool, which would include the publication of a risk indicator for extreme ramping events (see Section 6.3.3)

6.4.4. Measures to improve coverage of imbalances by BRPs

Introduction

In order to evaluate the impact of the offshore generation profiles on the system imbalance in normal and extreme conditions, assumptions had to be made on the ability of BRPs to cover imbalances. As explained in Section 4, the ability of BRPs to deal with offshore generation in their portfolio depends on various parameters, some of which are subject to uncertainties when looking at the time horizon of the future offshore wind parks. To cope with the uncertainty around the assumption of ability of BRPs to cover imbalances, best and worst cases were defined based on statistical analyses, specific extreme events and developments expected in the market. The impact analyses performed in the analyses on reserve capacity needs (Section 4) and on real-time system operation (Section 5) confirmed the expected sensitivity of results on this specific assumption.

[15] FRCE is equal to the ACE of an LFC Area

It is to be noted that the capacity of a BRP to neutralize its own imbalance or to perform reactive balancing can allow for a quicker correction of the system imbalance than the activation by Elia of FRR means, as the reaction of the BRP can be quicker than the full activation time imposed to a BSP when activating a balancing product.

The objective of the measures presented in this section is to have a positive impact on the coverage of imbalances by BRPs in normal and extreme conditions. As the measures concern BRPs and not directly wind parks, they would automatically apply also for the BRPs of existing wind parks.

Multiple BRPs on one access point

As offshore wind production is subject to unforecasted power variations and as the installed capacity of offshore wind parks is usually important (compared to traditional power plants), a BRP taking an offshore wind park in its portfolio is particularly exposed to large imbalances. In order to spread this risk over several BRPs, the existing access contract offers different possibilities to allow more than one BRP on one single access point.

Elia has identified several potential advantages to allow multiple BRPs on an offshore access point:

- Wind parks have more options when selecting a BRP
- BRPs manage smaller volumes, which allows them to better manage their risk and reduces the risks for the grid
- Even for a BRP willing to have a significant volume of offshore in its portfolio, it could make sense to avoid a too high geographical concentration of its production units. Taking the balancing responsibility for a part of several wind parks would allow the BRP to spread the risk over a wider geographical area and over several wind turbine technologies.

Elia plans to conduct a study[16] consisting on revising and improving existing schemes regarding the possibility to designate more than one BRP per access point as well as the interactions of those BRPs with other important roles such as Access Contract Holder (ACH), Sheduling Agent (SA), Operational Planning Agent (OPA)… In the event of positive conclusions, Elia foresees to present an implementation plan by the end of 2021. It's to be noted that the study is not limited to access points of offshore wind parks.

Ability of BRPs to manage their position

DTU provided statistics of the historical ability of each individual offshore BRP historically to cover imbalances and forecast errors. For confidentiality reasons, these statistics can't be disclosed. The general conclusion however is that significant differences have been observed up to now in the way offshore BRPs manage forecast errors. This could be explained by several factors (available tools, experience in offshore in Belgium and abroad, etc.).

[16] Elia proposed such a study to the CREG in the framework of the balancing incentives to be fixed for the year 2021

The impact of the power variations from the currently installed offshore capacity on the system imbalance is already significant. As demonstrated in Section 5, with a capacity extended up to 4.4 GW, this impact increases even more and is without comparison with other production means (thermal plants, but also variable production from PV and onshore wind).

The possibility to have multiple BRPs on one access point will contribute to spread the risk caused by offshore wind on the system imbalance. However, with up to 4.4 GW installed capacity, a single BRP having 30% of this volume in its portfolio would concentrate a risk of about 1300MW. In this event, Elia would consider, in line with the process of applying for the status of BRP as described in Article 217 of the Federal Grid Code and in Article 18(6)(b) of EBGL, putting additional focus on any means (tools, processes, experience, assets,…) that the BRP intends to use in order to cope with forecast errors and power variations. This would allow a constructive dialogue between Elia and the concerned BRP, aiming at raising awareness on the specific financial and operational risks related to offshore wind.

In the context of this process and considering the potential impact of offshore wind on future imbalance prices, the financial warranties requested to BRPs might have to be reviewed.

Finally, in cases of expected extreme events identified in day-ahead or in intraday, which could be forecasted storms or a high risk of ramping (see Section 6.3), all BRPs which have offshore wind in their portfolio would have to communicate on the means he intends to use to cover for the risk of extreme event.

7. Conclusions

This study aims at analyzing the impact of additional installed offshore capacity on the system and to formulate recommendations.

As a first step of the study, the **future offshore generation profiles** were evaluated by a consultant (DTU). Scenarios on different offshore wind turbine technologies and installed capacities were defined in collaboration with the stakeholders. The methodology to perform the simulations was defined and the model was validated based on measurement data from Belgian wind parks. Statistics were provided, showing the extent and the frequency of extreme ramping and storm events. Finally, the time series resulting from DTU's simulations were used as input for the next steps of the study.

Conclusions on the system's flexibility needs

Based on the methodology used and described in the latest adequacy and flexibility study, the relevant scenarios were re-assessed towards 2026 and 2028. It is concluded that the trends and conclusions of the study are confirmed concerning the ramping flexibility (to react on minute basis), fast flexibility (to react fully in 15 minutes) and slow flexibility (to react fully in 5 hours). It is observed that the increase in flexibility needs in 2026 and 2028, partially explained by a larger offshore generation capacity in 2026 and 2028 as formerly foreseen, is, to a certain extent, compensated by using the forecast errors calculated with the data provided by DTU. This can be explained as these data better take into account the geographical smoothing in comparison to the previous extrapolations of Elia's available data based on the 1st wind parks. This being less the case for the ramping flexibility where this effect is reduced by a slight increase in the flexibility needs due to increasing the resolution for the forecast error variations from 15' to 5'. Despite this effect, the former approach of upscaling Elia's 15' forecast errors and generation variations was a good approximate for analyses concerning flexibility and reserve capacity requirements. It is also expected to improve along with the increased offshore generation capacity to be observed.

Compared to the available flexibility means, for which there was no need for new simulations or updates. If the system is adequate, sufficient flexibility will be installed in the system to cover the flexibility needs, although it will not always be operationally available when needed. This means that upfront reservations (by BRPs or Elia) will remain necessary. This is the case for upward flexibility but also to a minor extent for downward flexibility. Note that new technologies such as decentralized storage and demand response are found to contribute in increasing extent to provision of the flexibility means. It is observed that towards 2028, additional fast and even the ramping flexibility can be found through remaining cross-border capacity after the intra-day during periods with high wind. However, although the remaining cross-border capacity may in 2026 and 2028 be of lesser constraint during these periods, the available volumes which can be accessed in the balancing time frame trough the balancing energy exchange platforms MARI and PICASSO are subject to large uncertainties.

Conclusions on Elia's reserve requirements

Results in the figure below show the expected average up- and downward FRR needs towards 2028 are expected to increase from 1039 MW and 1006 MW in 2020 towards respectively 1246 MW and 1111 MW in 2028. This observation is partially explained by the new offshore generation capacity and is at least valid in a reference case where the market's ability to cover forecast errors and portfolio imbalance keeps improving, in line with Elia's measures providing tools and incentives for BRPs to balance their portfolio, as well as increasing flexibility installed in the system.

It is shown that the impact of market performance can have a substantial impact, i.e. with a difference of average FRR needs up to 300 MW between a worst and best case. Note that the final dimensioning is conducted day-ahead, based on machine learning algorithms and historic system conditions and that market performance will automatically be taken into account in the dimensioning. Towards 2028, the dynamic behavior is found to increase substantially with larger variations between minimum and maximum FRR need, i.e. between 1000 MW and 1600 MW for upward FRR needs, and 600 and 1700 MW for downward FRR needs.

It is however shown that the impact of market performance can have a substantial impact, i.e. with a difference of average FRR needs up to 300 MW between a worst and best case. Note that the final dimensioning is conducted day-ahead, based on machine learning algorithms and historic system conditions and that market performance will automatically be taken into account in the dimensioning.

Finally, the split has been made between aFRR and mFRR needs based on the current method for aFRR dimensioning, as these values are used in the dispatch simulations. Note that in parallel of this study, a new method is being investigated to improve the aFRR dimensioning methodology.

Conclusions on real-time balancing

In order to evaluate the possible impact on real-time operation, a set of simulations have been conducted using historical ramping and storms events. The analysis included assumptions of both optimistic and pessimistic sensitivities to cover uncertainties about the future functioning of the market and technological developments (by the time the 2nd wave offshore capacity will be commissioned). The analysis identified several scenarios where the validation criteria that have been defined are violated, notably as the installed capacity increases for both ramping and storm events.

The impact analysis performed have shown a high sensitivity of violations towards the assumptions, in particular regarding the ability of BRPs to cover imbalances. Consequently, effective mitigations measures need to be prepared in the case that existing mechanisms and ongoing initiatives to improve the system imbalance would not be sufficient. Therefore, a verification of the assumptions made will be performed before the start of the tendering process of the new concessions.

Conclusions on mitigation measures

Finally, a preliminary list of mitigation measures has been established. Several mechanisms expected to have a positive impact on the system imbalance already exist and will be further monitored in the coming years. Actions that need to be investigated by Elia have been identified. Those could potentially have a positive impact in the medium to long term and require further development in the coming years before their effect can be quantified. The last group of measures imply technical and operational constraints for the wind parks and/or the BRPs.

Elia will use the period between the 1st and the 2nd consultation to perform at least following tasks:

- On the basis of the feedback from the public consultation
  - Perform if necessary sensitivity analysis on the scenarios used as input of the evaluations
  - Further assess the mitigation measures listed in this report or suggested by the stakeholders. When possible, the operational and financial effect of the mitigation measures will be quantified
  - Adapt when necessary the and possibly reruns with updated scenarios / sensitivity analysis
- Perform a benchmark with other TSOs on the basis of the results presented in this document

Stakeholders are welcomed to provide their suggestions and feedback on the present report in a public consultation from June 8, 2020 to July 8, 2020. Those will be taken into account when defining the next steps towards the 2nd consultation, planned to start in October 1, 2020. The final report will be published on December 23 the latest.

Annex A: DTU report on offshore generation profiles

Elia - MOG II System Integration – Public version

Department of Wind Energy E Report 2020

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DTU Wind Energy E-0203

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Preface

This study has been performed as a consultancy contract between ELIA and DTU Wind Energy following the “MOG II System Integration” request by ELIA.

Roskilde, Denmark, May 2020

Poul Sørensen
Professor

Content

Summary

This document is the final report of Elia's Consultancy project on MOG II System Integration.

The existing Belgian offshore fleet is one of the areas with the highest density installation of wind energy worldwide. This report studies the impact of the production variations and the forecast errors on the balancing of the Elia grid when extending the Belgium offshore fleet (MOG II project).

This report demonstrates the validation of DTU's CorWind model to capture the generation time series of the offshore wind power plants that were operating in Belgium beginning of 2018 (see chapter 6). It is thus considered valid for modelling the MOG II capacity extension.

The report documents the wind turbine technology trends and proposes installed capacity/technology scenarios for the MOG II wind energy fleet extension. The most important parameters for the purpose of this study are turbine specific power and hub height, and storm shutdown behaviour. Two different wind turbine specific powers are considered; a larger rotor with lower specific power (Technology B) produces larger capacity factors but is expected to represent higher cost turbines (compared to Technology A, with higher specific power). Three storm shutdown types are modelled and compared, with the "Deep" type providing least ramping during very high wind speeds. The "Moderate" type provides less reduction of ramping during high wind speeds compared to Deep.

The future wind plants increase the aggregated capacity factor of the fleet from BE 2018 towards the 4.4 GW scenarios, with Technology B showing significant increase compared to Technology A; this leads to more annual offshore generation with the same installed capacity despite of the additional wake losses from the new installations.

The standardized generation ramps are expected to be reduced towards the 4.4 GW of installations. This is caused by larger distances between plants (i.e., geographical smoothening). Fleet-level 5 min ramps are reduced more than 1 hour ramps. However, expressed in absolute power, ramps are expected to increase significantly in the future due to the larger capacity installed. In the 4.4 GW scenarios, ramps of more than 2 GW in 1 hour are expected to occur multiple times in a year. 1 hour down-ramp larger than 2.5 GW is expected approximately on one day in a year. Up-ramp of more than 2.5 GW in 1 hour is expected approximately on 2 or 3 days a year. Comparing high wind days (fleet-level mean wind speed > 20 m/s) and the rest of the days showed that most extreme ramps occur during high wind speed days, especially for 5 and 15 min ramps. However, an up-ramp larger than 4 GW within 1 hour was seen once in the simulation for non-storm days. This shows that very extreme ramps are possible on non-storm days, but they are unlikely. Even though similar size down-ramp was not seen in the simulations, it cannot be ruled out that such down-ramp events could not happen in the future.

It is possible to lose the full 4.4 GW of installed capacity in all studied 4.4 GW cases due to an extreme storm event. The number of years where this occurs is 6 or 7 out of the simulated 37 years for the 4.4 GW scenarios, depending on the technology scenario. Out of the 3 different storm protection technologies considered, the Deep storm shutdown type results in the lowest loss of power and in less fast (5 or 15 min) ramping during storms. The following numbers are for

the 4.4 GW scenarios. For 15 min ramps, > 2 GW down-ramps are seen in the simulations a few times over the 37 years for the regular 25 m/s direct cut-off storm shutdown type, but such event was not seen for scenarios with the Deep or Moderate type. The Deep type shows a reduction of down-ramps compared to Moderate: 15 min down-ramps of > 1 GW and > 1.5 GW are approximately half as likely for the Deep than for the Moderate type. 5 min down-ramps are also reduced: a 5 min down-ramp of > 0.5 GW is expected to occur on multiple days a year for the 25 direct cut-off, on 1 or 2 days a year for the Moderate and on less than one day a year for the Deep type.

For 1 hour ramps in the 4.4 GW scenarios on high wind days (fleet-level wind speed > 20 m/s), a down-ramp of more than 2 GW is expected to happen on a few days over a year with the 25 m/s direct cut-off type. For similar scenarios with the Deep type, such event is expected on less than one day a year. However, on the fleet-level (4 or 4.4 GW), the most severe 1 hour down-ramps are relatively similar for all storm shutdown types. On storm days, extreme up-ramps are more likely than similar size down-ramps; this is affected by the storm shutdown slowing only the shutdown and not the restart part of the power curve. Mitigation of such up-ramp events after storms should be considered as they represent some of the largest power fluctuation events.

Geographical smoothening is also expected to decrease aggregate forecast errors (in standardized generation). Large forecast errors are more likely during high wind speed days (max wind speed > 20 m/s). The Deep storm shutdown type shows slightly lower forecast errors during high wind speeds days compared to the other studied storm shutdown types.

Analysis of historical data from 2018-19 shows that the increasing capacity from 877 MW to 1548 MW of offshore wind power has increased the offshore wind power forecast errors in the Elia system. The analyses of correlation between offshore wind power and system imbalance show that the wind power forecast error is much more correlated with imbalance than the wind power production and forecast, meaning that the forecast errors is the main cause for imbalances, whereas the impact of wind power variability is mitigated by the spot market and intraday trading. This analyses also indicates that the correlation coefficients between wind power and system imbalance are generally increasing for increasing installed capacity, but this trend is not very significant.

Statistical analyses of the individual BRPs imbalances show significant differences in the statistical probability density functions of different BRPs. This indicates that there is a significant difference between BRPs in the way that they manage to handle the forecast errors.

Finally, the analysis of forecast error correlation with individual BRP imbalances, BRP sum imbalances and system imbalances also shows significant increase of the correlations between forecast errors and imbalances during days with high forecast errors, extreme ramping events and during storm events.

1. Introduction

The planned installed capacity of wind farms in the Belgian offshore area by the end of 2020 is approximately 2.3GW, see Table 1. In the Marine spatial planning 2020-2026, the Belgian minister competent for the North Sea has established the framework for an additional production zone of 281 km² (at the frontier with France), in addition to the wind zone of 225 km² which already exists (at the frontier with the Netherlands). This new zone will allow up to 2.1GW additional installed capacity. The assumption used is that this additional capacity will be commissioned between 2026 and 2028.

Name	MW	Manufacturer	Turbine model	Turbine MW	Rotor diameter m	ws_shutdown_begin	ws_shutdown_end	ws_restart_begin	ws_restart_end	Hub height m	Number of turbines	Commissioning year
Belwind	165.0	Known	Known	3.0	90	Based on measured data				Known	55	2010
Nobelwind	165.0	Known	Known	3.3	112	Based on measured data				Known	50	2017
Norther	370.0	Known	Known	8.4	164	Deep type				Known	44	2019
Northwester _2	218.5	Known	Known	9.5	164	Deep type				Known	23	2020
Northwind	216.0	Known	Known	3.0	112	Based on measured data				Known	72	2014
Rentel	308.7	Known	Known	7.4	154	Deep type				Known	42	2018
Seastar	252.0	Known	Known	8.4	164	Deep type				Known	30	2020
Mermaid	235.2	Known	Known	8.4	164	Deep type				Known	28	2020
C_Power_1	30.0	Known	Known	5.0	126	Based on measured data				Known	6	2009
C_Power_2	147.6	Known	Known	6.2	126	Based on measured data				Known	24	2012
C_Power_3	147.6	Known	Known	6.2	126	Based on measured data				Known	24	2013
Noordhinder Noord	Tech data depends on the scenario											2026
Noordhinder Zuid	Tech data depends on the scenario											2026
Fairybank	Tech data depends on the scenario											2026

Table 1. Technical characteristic of the Belgian offshore wind power plants. For the existing OWPPs with measurements, turbine shut-down and restart wind speed limits are based on measured wind speed and generation data. OWPPs with hi-wind operation turbines are assumed to follow the "Deep" type shown in Figure 10 (other information was not available).

The objective of this study is to define the impact of the new wind parks on storm events, wind power ramping events and wind power forecast errors. An historical analysis of the impact of wind parks on system imbalance is performed in order to support Elia in defining the expected reactions of BRPs once the additional capacity will be commissioned. The consequences for the grid as well as the definition of possible necessary mitigation measures are not included in the scope of this study.

The study is based on analysis of existing data focusing on the latest 2 years 2018-19 and on simulations of specified scenarios for the future offshore wind power in the existing and the new zones.

The report is structured as follows:

Chapter 2 describes the trends and selected wind turbine technologies relevant for the MOG II extension in 2026. This includes the general technical specifications of the turbines such as specific power, rated power, rotor diameter and hub height, as well as their power curves including storm protection operation.

Chapter 3 explains the root causes for ramping events and it uses measured ramp event examples on the operation of existing wind farms. This chapter shows that the main cause for ramping events is wind speed fluctuations.

Chapter 4 presents the scenarios studied in terms of installed capacity and of technology for the MOG II extension. It also includes the locations of the plants currently in operation used in model validation.

Chapter 5 describes the methodology used to simulate the operation of the plants in a given scenario. This includes description of CorWind, the core model for simulating the time series of wind energy production of a both large spatial scale and temporal length. Additionally, the methodologies for wake modelling and storm shutdown modelling are explained. Finally, Chapter 5 highlights the methodology for filtering generation measurements in order to represent future installed capacities.

Chapter 6 documents the model validation based on the generation and wind speed measurements from the currently operating plants. Validation results are detailed on both plant level and on aggregated (fleet) level for several variables such as capacity factors, wind speed, generation probability distributions, generation, correlations, ramps, probability density functions (PDFs) and ramp correlations. Additionally, this chapter presents the model validation in terms of storm shutdowns, high wind speed probabilities, and forecast errors for different forecast horizons.

Chapter 7 analyses the basic statistics of the results for all capacity/technology scenarios in terms of capacity factors, standard deviation of standardized generation and PDF of standardized generation.

Chapter 8 presents the statistical analysis of ramping events for several time periods (5 minutes, 15 minutes and 1 hour) in terms of standardized generation and in actual GW of power fluctuation. Additionally, this chapter compares ramp likelihoods for days without high wind speeds in order to dissociate ramp events due to wind variations from ramp events due to storm shutdowns. Finally, this chapter concludes and gives input for mitigation of ramps in section 8.5.

Chapter 9 introduces the methodology used for identification of storm events from the 37 years of simulated generation. Additionally, this chapter analyses the resulting statistics of frequency of occurrence of such events as a function of their severity for each installed capacity/technology scenario. This chapter gives conclusions and input for mitigation of storm-related ramp events in section 9.6.

Chapter 10 presents the statistical analysis of forecast errors in terms of standardized generation and in GW for the forecasting horizons currently used by Elia (Day-ahead, intraday and “Last”). Additionally, this chapter shows how the forecast errors change for days with large ramps or storm.

Chapter 11 analyses imbalances of individual balancing responsible parties (BRP) with offshore wind power, and at the system level. At system level, the sum of BRP imbalances and Elia’s system imbalance are analysed. The relationship between wind power and imbalances are presented, with special focus on the correlations between wind power forecast errors and imbalances, based on the data from real operation during the latest 2 years 2018-19.

2. Technological benchmark

The trends in offshore turbine technology are analysed in terms of turbine capacity, specific power and hub height. The trends combine the current turbines installed or planned in Belgium and the Netherlands, the Danish Energy Agency technology catalogue [1], and the prototype turbines from different manufactures currently being tested for certification. See Figure 1.

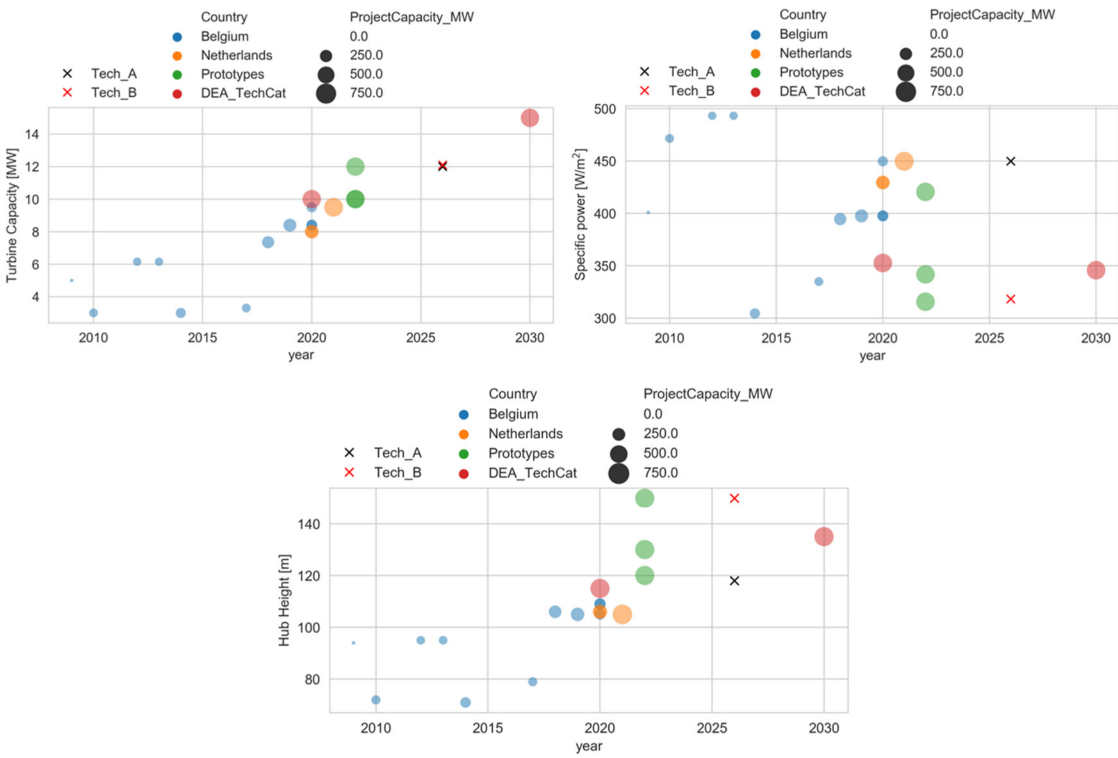


Figure 1. Trends in turbine capacity, specific power and hub height for offshore turbines.

Based on analyzing the trends from historical wind turbine data including prototype information online, two technology scenarios for the potential future offshore wind power plants (OWPPs) to be commissioned in 2026-28 are used. This study does not aim to use specific manufacturer technologies for those future wind turbines, but rather to make generic assumptions and supplement with sensitivity analyses where manufacturer differences and other uncertainties are considered important for the expected results regarding ramping and impact on system imbalance.

Two technology scenarios as listed in Table 2 have been validated by the stakeholders in the Elia workshop/meeting in Brussels the 23 January 2020. The two scenarios assume same rated power but different specific power (W/m^2). We are aware that in reality, there will be a few MW range of rated power from different manufacturers, but we do not expect this difference in rated power to have significant impact on the results. From the available information about offshore wind turbine prototypes, we have observed significant differences in specific power which will impact power curves and thereby have possible impacts on ramp rates for wind speeds below rated. Given the rated power, the different specific powers will influence the rotor diameter and the hub height as shown in Table 2.

Table 2. Technology scenarios for offshore wind turbines for additional installations

Technology scenario	A	B
Rated power	12 MW	12 MW
Rotor diameter	184 m	220 m
Hub height	118 m	150 m
Specific power	450 W/m^2	316 W/m^2

Those assumptions lead to the generic power curves shown in Figure 2 for the two technology scenarios, Tech A and Tech B. On top of this, based on manufacturer brochures and literature review, we propose three high wind technology scenarios also shown in Figure 2. For 25 direct cut-off, which is considered as baseline, the wind turbine will shut down when the 10 minute average wind speed exceeds 25 m/s. For HWS Moderate, the power will reduce for increasing wind speeds until the wind turbine shuts down at 28 m/s. Finally, for HWS Deep, the power will reduce for increasing wind speeds until the wind turbine shuts down at 31 m/s.

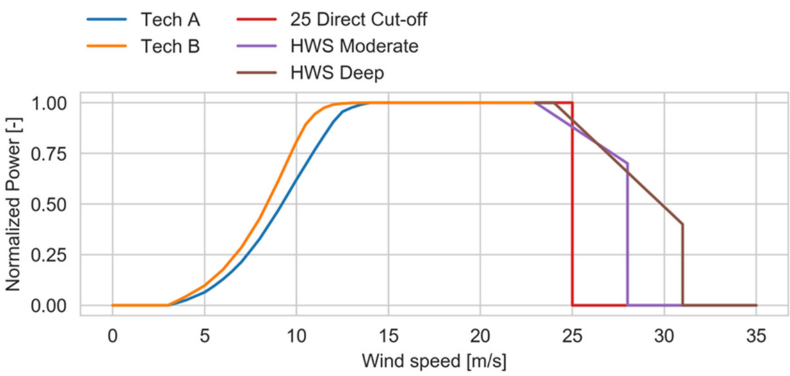


Figure 2. Power curves for assumed technology scenarios and storm shutdown scenarios.

Regarding storm shutdown and restart, we propose assumptions about the averaging time(s) and corresponding wind speed thresholds. In a previous study performed in the EU TWENTIES project, we assumed shutdown protections for averaging times 10 minutes (average), 30 seconds (gust) and 1 second (instantaneous). The corresponding wind speed thresholds increased for decreasing average times. We found from wind farm observations and from our simulations that a significant part of the turbine shutdowns where activated for all 3 average times.

The proposed generic wind turbine protection settings for the 3 high wind scenarios are shown in Table 3. As for the technology scenarios in Table 2, we are not aiming to use specific manufacturer technologies for those future wind turbines, but rather to make generic assumptions and supplement with sensitivity analyses where manufacturer differences and other uncertainties are considered important for the expected results regarding ramping during storm and resulting impact on system imbalance. So, the main purpose is to have the 3 major high wind shut down scenarios simulated to be able to compare them.

Table 3. Generic high wind turbine protection settings for the 3 high wind scenarios

Event	Averaging time	25 Direct Cut-off	HWS Moderate	HWS Deep
Shutdown	10 min	25 m/s	28 m/s	31 m/s
Shutdown	30 sec	28 m/s	31 m/s	34 m/s
Shutdown	1 sec	32 m/s	35 m/s	38 m/s
Restart	10 min	22 m/s	23 m/s	24 m/s

Finally, fast wind direction shifts could cause changes on the power because the power depends on the yaw error. However, provided that the yaw control dynamics is sufficiently fast – e.g. max 1 minute –the effect of yaw control is expected to be negligible in the studies looking at ramps at the wind farm level. Thus, yaw control dynamics are not considered in the simulations.

3. Root causes of ramping events

Wind farms are normally operated in a mode where the wind turbines generate maximum possible power. In this normal operation mode, changes in the power output from a wind farm (called “ramping events” in this study) occur continuously because of the variable nature of the wind field feeding the wind farm. However, since the wind farm power can be reduced below the available power as a consequence of control commands issued by the operator, ramping events also occur due to intentional control actions. This chapter describes only the root causes for ramping events during normal operation where the operator is not dictating ramps because of control commands.

Considering their expected frequency and the means available to manage them, root causes of ramping events below 300MW (out of the 4GW+ installed capacity) will not be analysed in detail by Elia. Therefore, this chapter will focus on identifying the root causes for ramping events above 300MW.

The main cause for ramping events is wind speed fluctuations. Even though the instantaneous (e.g. 1 second average) wind speeds differ significantly between wind turbines in a wind farm, the 1-5 minute averages are quite correlated, and as a result, the wind farm power can ramp significantly in 5 minutes. Another root cause for ramping events can be changes in wind direction. Such wind direction changes affect:

- The wake from upstream wind farms and the wakes inside the wind farm, which causes some ramping in the total wind farm power.
- When the change in wind direction is fast, yaw misalignment of the wind turbines is possible. However, since the wind turbine control systems adjusts the yaw angle at least once in a minute and the wind direction changes take several minutes to affect all wind turbines, the yaw misalignment will not have significant impact on the total wind farm power.

Coming back to the main cause for ramping events, Figure 3 shows an example of wind farm power ramps affected by wind speed fluctuations around the steep part of the power curve. It is seen that 10th August in the evening between 22 and 23, the power decreases from full to less than half in less than one hour which is a result of a reduction in wind speed from approximately 13 m/s to approximately 8 m/s in the same period.

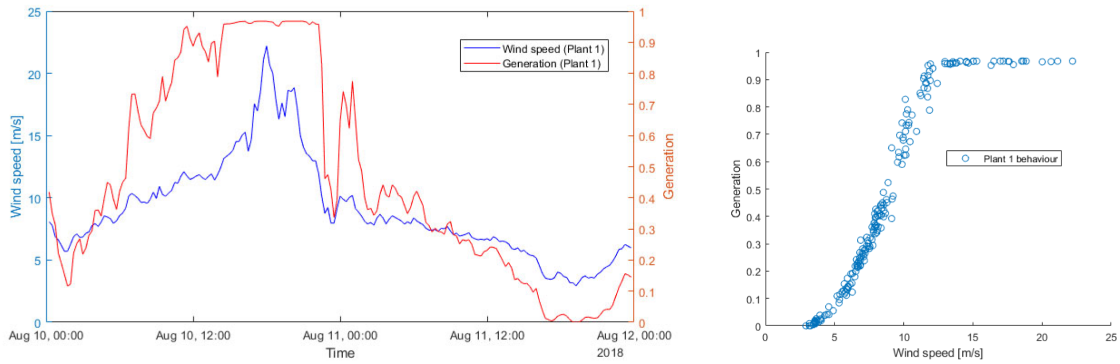


Figure 3. Example of power ramps from a single wind farm, affected by wind speed fluctuations around the steep part of the power curve.

For a single wind farm, such power reductions are often below the critical value of 300 MW, but with several offshore wind farms close to each other, the wind speeds are highly correlated, and therefore the total offshore wind power ramping can become significant.

The effect of strong correlation between wind power generated by two closely located wind farms is illustrated in Figure 4. It is seen that the second wind farm (Plant 2) reduces power even more on the 10th August in the evening, although this happens over a couple of hours. It is also noticed that the correlation between the two wind farm powers is 0.94, which is quite significant.

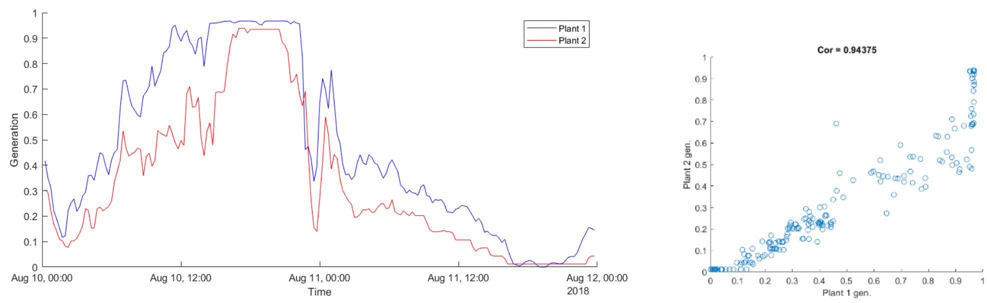


Figure 4. Example illustrating correlation between power ramps from two closely located wind farms.

Although the correlation between the two wind farm powers is quite significant, the correlation between fast ramp rates is relatively low. This is shown by the 15 minute ramp rates for the same case in Figure 5 where the correlation between ramp rates are only 0.17

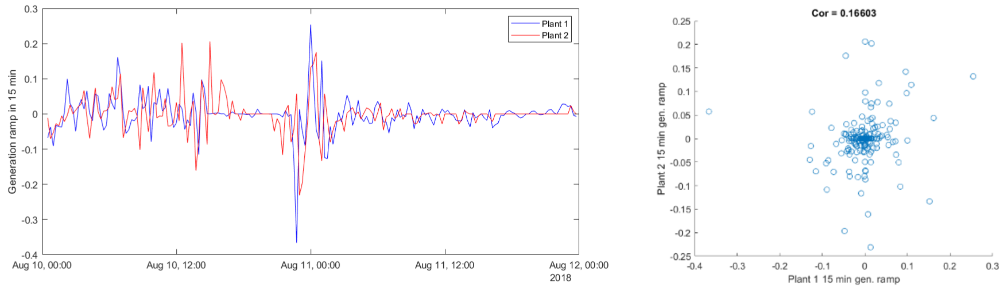


Figure 5. 15 minute ramp rates from two closely located wind farms.

A more extreme ramping event happened on the 15th October 2019. Figure 6 shows variations in wind speed measured at a single point together with power from 6 wind farms during the last 12 hours of that day. It is seen that the wind speed is quite stable until 20:00, but then the weather becomes more unstable, and especially between 21:30 and 22:00, there is a very significant spike in the wind speed, causing also the power form all wind farms to peak. Although this is not visible from the shown wind speed (measured at 43.96 m height on a single meteorological mast located on the MOG I platform), the spatial smoothening causes this wind speed spike to hit the wind farms at displaced times, which can be seen in the power from the individual wind farms. This example also illustrates that in extreme cases with very fast wind speed ramp rates, the spatial smoothening reduces the effect on total wind power significantly compared to the effect on the individual wind farms.

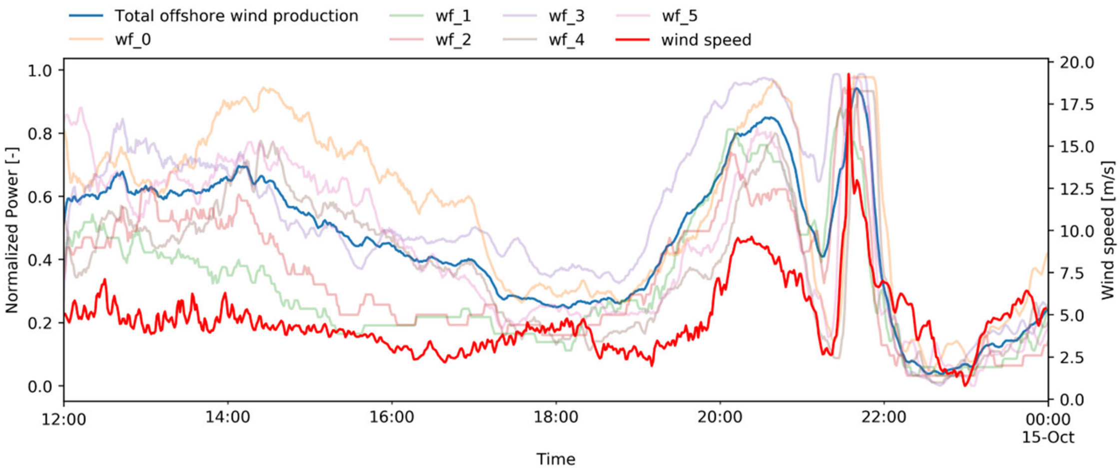


Figure 6. Wind speed and wind power from 6 wind farms 15th October 2019. Wind speed at 43.96m height above sea level from a single MET mast (WINDSNELHEID) located on the MOG platform.

4. Studied scenarios

This chapter starts by presenting the geographical positions of the Belgium OWPPs in the different studied scenarios. The first section shows the OWPPs used in CorWind model validation and Section 4.2 shows the OWPP installations scenarios towards a total offshore installation capacity of 4.4 GW in the Belgian offshore region. Figure 7 shows all the OWPPs considered in the entire study.

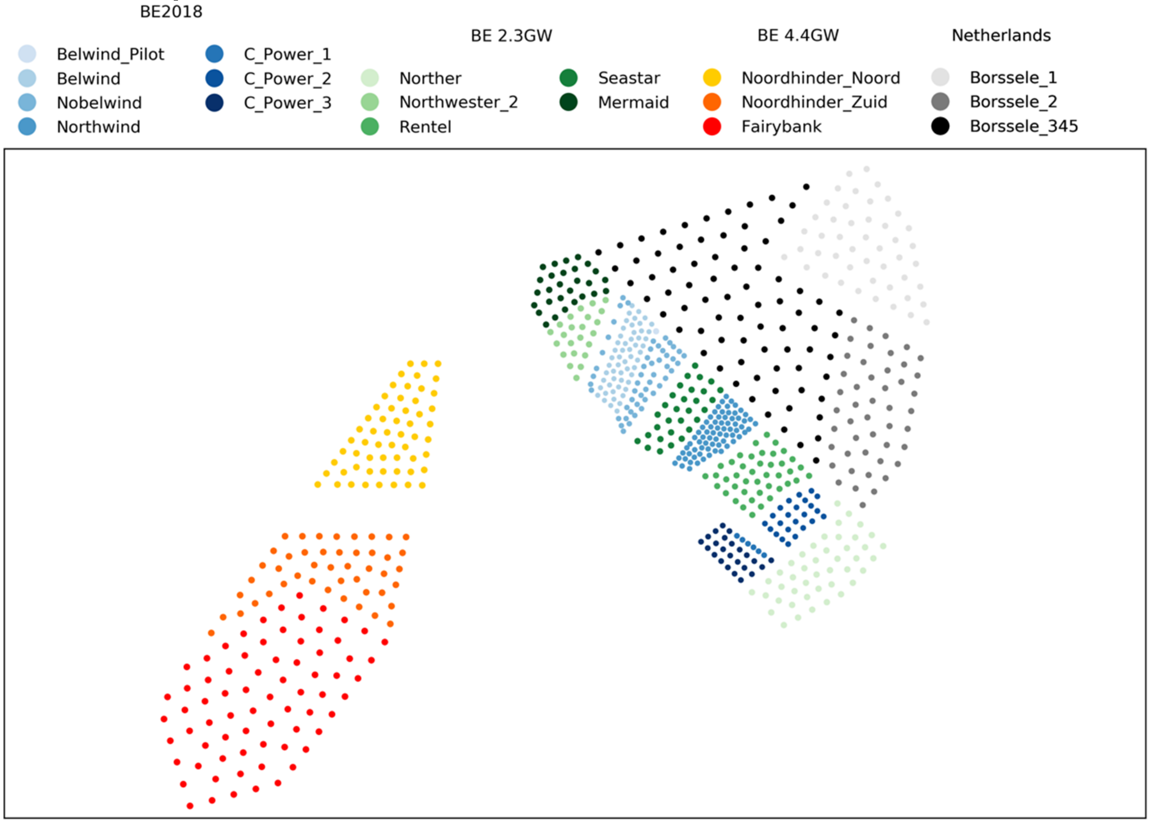


Figure 7. Plant and turbine locations for the different stages of offshore wind installations. The Dutch plants are taken into account when modelling external wake impacts on the Belgian OWPPs.

4.1 Offshore plants in model validation

The plants that belong to the BE2018 group (Belwind, Nobelwind, Northwind, C_Power_1, C_Power_2 and C_Power_3), see Figure 7, are used in the model validation. These plants are selected because they have multiple years of measurements available (see Section 6).

4.2 Extended capacities

The several stages of the installations of the Belgium offshore wind power fleet considered in the present study are shown in Figure 7. The BE 2.3GW stage consists of the full MOG I fleet (this includes the plants in BE2018 as well as Norther, Northwester 2, Rentel, Seastar and Mermaid).

The BE 4.4GW scenario consists of the estimated locations of the future MOG II plants: this scenario includes the plants in the BE 2.3GW as well as Noordhinder Noord (~700 MW), Noordhinder Zuid (~550 MW) and Fairybank (~850 MW). Two additional installation scenarios are modelled. In BE 3.0 GW, only Noordhinder Noord is considered in addition to the 2.3 GW. In BE 4.0 GW, all of the OWPPs belonging to 4.4 GW are considered; however, they are all considered to have lower installed capacities.

The Borssele offshore cluster in the Netherlands is considered because large wake effects are expected due to its proximity to the Belgian fleet. On the contrary, the planned offshore plants in Dunkirk France are not modelled because their larger distance to the Belgian fleet makes them irrelevant in terms of farm to farm wake losses.

4.3 The scenarios

For the installation scenarios described in the previous section, different turbine technologies are modelled. The technologies are as presented in Chapter 2. The resulting scenarios, considering the different amounts of installations and different technologies, are listed in Table 4. Going from BE2018, which is used for model validation, the installed capacity increases towards 4.4 GW. All of the scenarios with 3.0 GW or more installed have the same 2.3 GW as the existing installations with fixed technology; then, different amounts of additional installations with different technologies are added to the 2.3 GW to reach the total installed capacity of the scenario.

Table 4. The studied scenarios.

<table>
<tr><th>Name</th><th>Installed capacity (MW)</th><th>Tech type</th><th>Storm shutdown type</th></tr>
<tr><td>BE 2018</td><td>877</td><td>Known existing data</td><td>Known existing data</td></tr>
<tr><td>BE 2.3 GW</td><td>2300 (approximately)</td><td>Known data</td><td>Known data</td></tr>
<tr><td rowspan="6">BE 3.0 GW</td><td rowspan="6">2300 + 700 additional</td><td rowspan="3">Tech A</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
<tr><td rowspan="3">Tech B</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
<tr><td rowspan="6">BE 4.0 GW</td><td rowspan="6">2300 + 1700 additional (Noordhinder Noord, Noordhinder Zuid and Fairybank; all with lower installed capacity)</td><td rowspan="3">Tech A</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
<tr><td rowspan="3">Tech B</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
<tr><td rowspan="9">BE 4.4 GW</td><td rowspan="9">2300 + 2100 additional (Noordhinder Noord, Noordhinder Zuid and Fairybank)</td><td rowspan="3">Tech A</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
<tr><td rowspan="3">Tech B</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
<tr><td rowspan="3">Tech A/B</td><td>25 m/s</td></tr>
<tr><td>Moderate</td></tr>
<tr><td>Deep</td></tr>
</table>

Notes related to Table 4:

- For BE 3.0 GW, BE 4.0 GW and BE 4.4 GW, the tech type and storm shutdown type are for the additional installed capacity; the 2300 MW part has technology specified based on known existing and planned OWPPs.
- The Tech A/B type for BE 4.4 GW has a mixture of Tech A and Tech B installations: Noordhinder Noord (~700 MW) has Tech A and Noordhinder Zuid (~550 MW) and Fairybank (~850 MW) have Tech B.

5. Methodology

This chapter presents the modelling methodology used in the MOG II analyses. This includes the CorWind tool for simulating the time series and wake modelling for including wake impacts in the CorWind simulations. Modelling of plant-behaviour during storms is also presented, and Section 5.4 explains how a filtering process is used on measured data from 2018-2019 to provide representative time series for the future scenarios based on measured time series.

5.1 CorWind

CorWind is DTU Wind Energy's tool for simulation of wind power times with realistic spatial and temporal correlations. It is the wind simulation part of the CorRES tool, which includes also solar generation simulation capabilities [2]. CorWind uses a database of mesoscale weather time series in hourly resolution over all Europe as input, and therefore it can capture the spatiotemporal variability for large scale simulations. DTU's database includes 37 years of meteorological data (1982-2018) produced using the Weather Research and Forecasting (WRF) mesoscale numerical weather prediction model [3]: WRF uses the ERA-Interim weather reanalysis datasets produced by the European Centre for Medium-Range Weather Forecasts as boundary conditions and simulates the weather over Europe with resolutions of 10 km. The downscaling from the coarser ERA-Interim data to the 10 km x 10 km resolution grid is carried out using the downscaling methods presented in [4], [5]. More information on the WRF model setup for reaching the final mesoscale data can be found in [6].

Compared to most other tools for large-scale wind power simulations, CorWind includes intra-hour fluctuations which are not captured correctly by mesoscale models even with high spatial and temporal resolutions and also the turbulent fluctuations within 10 minutes resolutions [7], [8], [9]. Information on why the mesoscale modelling systems (such as WRF) cannot capture all variability in wind can be found in [10]. The missing fluctuations are added to the mesoscale WRF data using stochastic simulation [11].

The combination of mesoscale WRF data and stochastic simulation allows two types of simulations: (1) large scale regions on continental domains with several wind power plants in resolutions of up to 5 minutes over 37 years; (2) detailed plant simulations that model each individual turbine; these simulations are required to understand the impact of storm protection technologies, which are usually specified on turbine-level rather than plant-level.

Due to the limitations of CorWind, it is currently not possible to run the simulations in 1min resolutions for the full Belgium offshore fleet over the 37 years. A resolution of 5min has been selected as it provides a compromise between the computational time and the limited added information of the within-10-minute fleet power fluctuation in both simulations and in the measured data in 1min resolution. For each simulation a reduced 15 min resolution dataset is produced by taking the mean of each variable in 5 minute resolution (or 1min resolution for the measured datasets) within each 15 minutes period. The 15min resolution data are calculated from the 5min data by taking the mean over the 15min and by shifting the resulting timeseries by 7.5min to ensure that there is no lag between the 15min and 5 min resolution timeseries.

5.2 Wake Modelling

As turbines and plants in the Belgium offshore fleet are often tightly spaced, significant wake effects are expected. Wake effects are modelled using the engineering wake model proposed by Bastankhah and Porté-Agel [12]. The wake model consists in Gaussian wind speed deficits, linear wake expansion and squared sum wake deficit superposition. This model is used because of its simplicity and because it has been formulated to hold mass and momentum conservation equations in the wake flow behind a turbine, while other engineering wake models like Jensen/Park do not. DTU's PyWake implementation of the wake model used in this study is available as open source code in https://topfarm.pages.windenergy.dtu.dk/PyWake/.

The wake model is used to generate a plant power curve by simulating the power outcome of the plant as function of the mean wind speed and mean wind direction over the whole plant. The plant power curve includes the wakes produced by other plants nearby, by modelling all the turbines within 40 km distance from each turbine within the plant. The resolution of the wake modelling has been chosen to be 1 degree in wind direction and 0.5 m/s in wind speeds. Finally, CorWind uses the plant power curve to interpolate the power produced by each plant on each time stamp.

An example of the wake modelling approach is shown in Figure 8 for an example OWPP in the BE2018 scenario. It can be seen that the internal wake losses are one order of magnitude larger that external wake losses. Both effects are captured in the plant power curve.

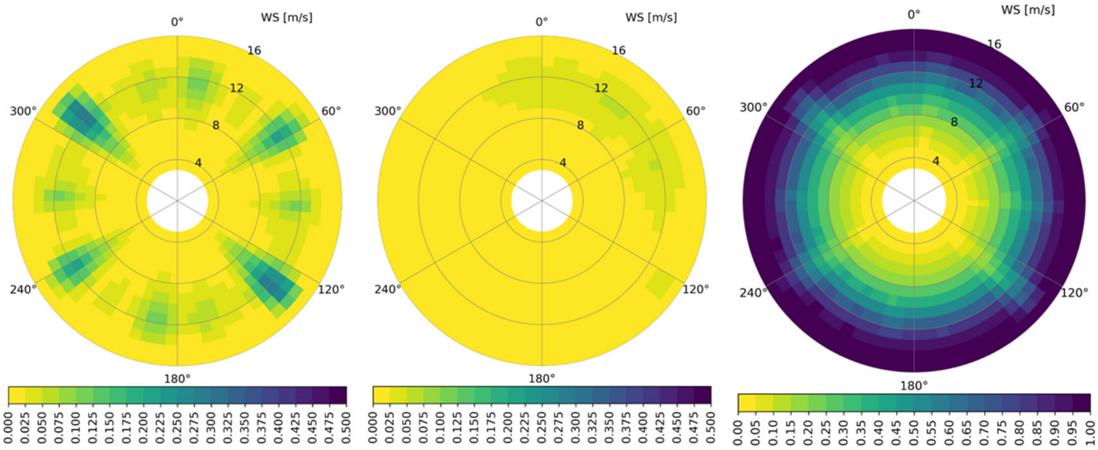


Figure 8. Example of wake modelling results for an OWPP: Left: internal wake losses; centre: external wake losses due to nearby plants; and right: plant power curve.

5.3 Storm shutdown behaviour

When simulating multiple years of generation time series with CorWind on 5 min resolution for multiple OWPPs, the simulations need to be done on plant-level; simulation of individual turbines is not feasible for such long time series. However, as the storm shutdown behaviours are given on turbine-level (Figure 2), the behaviours of the different shutdown technologies need to be modelled on plant-level. This section describes how the turbine-level shutdown information are transferred to plant-level models.

5.3.1 Turbine-level storm shutdown model

Individual turbine shutdown can be modelled in simulations with up to 1 s resolution in CorWind (while the mesoscale data are hourly, CorWind creates up to 1 s time series using stochastic simulation, as described in Section 5.1). These simulations are used to study how a specific turbine high wind speed technology translates into the plant level shutdown/restart behaviour. In these simulations, each turbine in a plant is modelled. Because of the high temporal resolution and turbine-level resolution of these simulations, only specific events (one or a few days) are simulated. A selection of high wind speed events has been taken from the 37 years of meteorological data to represent multiple high wind cases.

In addition to the shutdown operation, the turbine-level model considers the restart operation. An example is shown Figure 9. The continuous line is effective until the turbine is shut down due to too high wind sped (the wind speeds in the figure are 10 min averages). After the shutdown, the wind speed has to get lower than the restart limit before the turbine starts to produce again. This effect is called hysteresis: it causes a time lag between the shutdown and restart operation, as it takes some time before wind speed gets lower than the restart limit after a storm event.

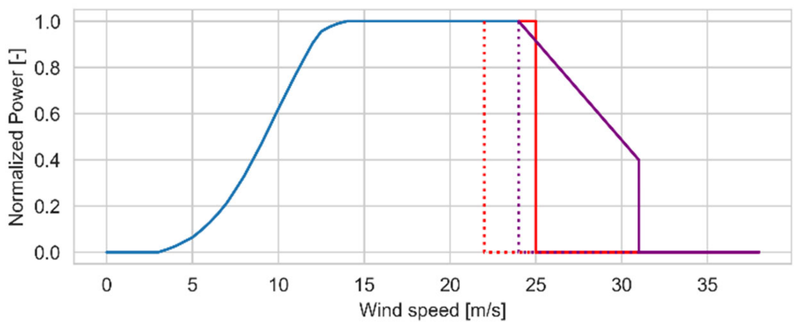


Figure 9. Storm shutdown and restart operations for the HWS Deep (magenta) and 25 m/s cut off (red) types. The dashed lines show the restart limits.

5.3.2 Resulting plant-level storm shutdown behaviours

The resulting plant-level storm shutdown behaviours for the three different shutdown types are shown in Figure 10. The blue dots show results from the 1 s resolution turbine-level runs; the red lines show the plant-level model based on the turbine-level simulations (the dashed line shows the plant-level power curve without the shutdown procedure: this line shows the power curve considering the controlled reduction of generation at high wind speeds, but without the shutdown action that takes the generation all the way to zero).

In Figure 10, it can be seen that the plant-level curve is smoother around the change from rated power to the part where generation is reduced compared to the turbine-level curve. Also, the cut-off does not happen as immediate on the plant-level: even for the 25 direct cut-off type, the plant does not completely shut down when the plant-level 10 min wind speed gets higher than 25 m/s. This is because it is unlikely that all the turbines of the plant reach a wind speed higher than 25 m/s exactly at the same time.

Plant-level hysteresis modelling is part of the model shown in Figure 10 with red lines. This means that if wind speed decreases after reaching a wind speed value over the shutdown limit, the plant will remain partly in shutdown before the wind speed gets lower than the restart limit. This models the phenomena where some of the turbines of the plant are in shutdown, whereas others still generate.

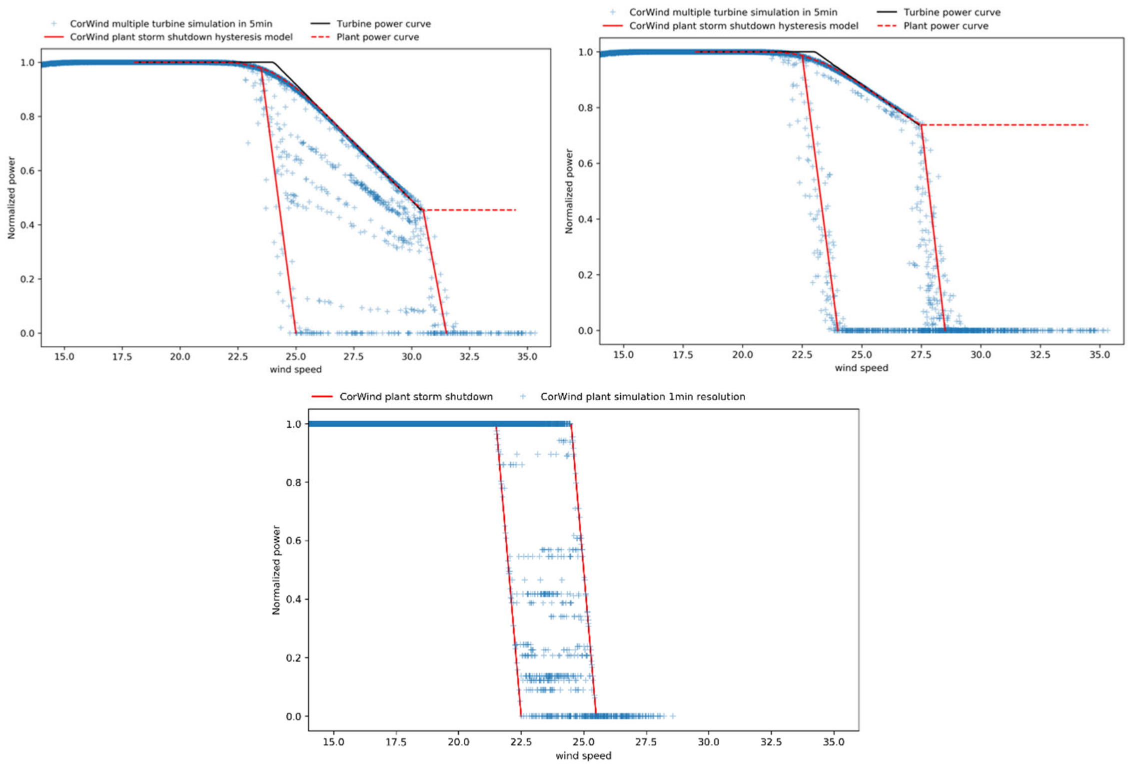


Figure 10. Calibration of storm-shutdown models in CorWind based on aggregated individual turbine simulations for different high wind speed storm operation technologies: top left: Deep; top right: Moderate; and bottom: 25 direct cut-off

5.4 Filtering measured data to represent a future scenario

Results presented in this report are based on simulated data from CorWind. These simulations relate to meteorological data from 1982 to 2018. However, the meteorological data cannot be taken to represent the reality exactly on 5 min or even hourly resolution (see Section 5.1): even though the high and low wind events happen approximately at the same times in the meteorological data and in reality (measured data), e.g., the exact time when a storm event affects an OWPP in the simulation is not the same as in reality. In addition, the stochastic simulations in CorWind, which add the missing variability to the data to better represent the ramp rates, do not add ramps at the same times as in measured data. For these reasons, the results from CorWind are assessed statistically; e.g., how many days in a year on average a significant ramp event is expected to occur.

However, in order to evaluate the impact of the additional capacity on the assessment of the flexibility needs and dimensioning of balancing reserves, Elia needs to combine offshore wind time series representing a future scenario to measured data from other sources (e.g., onshore wind and solar generation, load). Due to the reasons explained above, the simulated data cannot be combined to measured data as it may cause correlations between the different sources to be incorrectly represented. Thus, DTU has created a process where measured historical offshore wind generation data can be filtered to represent a future scenario with more OWPPs installed. The following sections explain how this process works for actual and forecasted generation.

5.4.1 Transformation and filter for actual generation

The starting point for applying the filter on 2018 and 2019 data are the measured 1 minute resolution generation data provided by Elia for each OWPP. However, as it was noticed that the 1 minute data includes control actions, they were first removed. Control actions cause variability in the data which are not caused by weather variability; an example can be seen in Figure 11, where an OWPP drops down for a significant time period (wind speeds are not high, so this is not caused by storm shutdown), causing an extreme 1 min up- and down-ramp.

The data processing consists on removing the individual plant production (at the moment it occurs and during the following 15 min) when both of the following conditions are met:

- 1 min power fluctuation is above 0.1 of the total installed capacity
- Fleet wind speed is lower than 18 m/s

The resulting distribution of 1 min fleet (BE 2018 installations) power fluctuations is shown in Figure 12. Note that the removal of the events has a marginal impact on the statistics of the 1 min power fluctuations in terms of mean, standard deviation (std), 1% quantile and 99% quantile. The main impact can be seen in the minimum (min) and maximum (max), as expected.

After the control actions have been removed, the measured data from the individual OWPPs that belong to BE 2018 (see Section 4.1) are aggregated and taken to 5 min resolution. This time series is then used as the starting point for the filtering process.

First, the 5 min resolution time series is transformed to a time series that represents the statistics of an extended capacity scenario, e.g., the 4.4 GW scenario with Tech B. The transformation considers the probability distribution function (PDF) of the time series; it applies the increase in capacity factor, as shown in Chapter 7, to the time series. The transformation considers also other statistics, such as standard deviation (SD) and percentiles, as the entire PDF is transformed. This is done using probability integral transformations based on the CorWind simulations of the BE 2018 and the extended capacity scenarios. Figure 13 shows the transformation procedure: first on the simulated data, and then as applied on the measured data (bottom subplot).

A filter has been designed to consider also the temporal dependency structure. This is required to capture the impact of geographical smoothening on reducing the standardized generation ramp rates, as shown in Chapter 8. The filter is a linear combination of three Gaussian moving average operators calibrated to match the autocorrelation of the extended capacity time series without producing lag in the output. An example of the autocorrelations before and after the filter can be seen in Figure 14: when applying both the transformation and the filter on the BE 2018 data, the resulting time series shows the same temporal correlation structure as the BE 4.4 GW Tech B data.

The results of applying the probability integral transformations and geographical smoothening filter on the 5 min measured BE 2018 aggregate generation can be seen in Figure 15. The reduction in 5 min ramp SD is similar to the CorWind simulation results on 37 years (see Section 8.1).

The filtering process is not valid for storm shutdown events. The high wind speed events (fleet-level wind speed > 22 m/s) are thus identified and filtered time series values are not given for those high wind speed events.

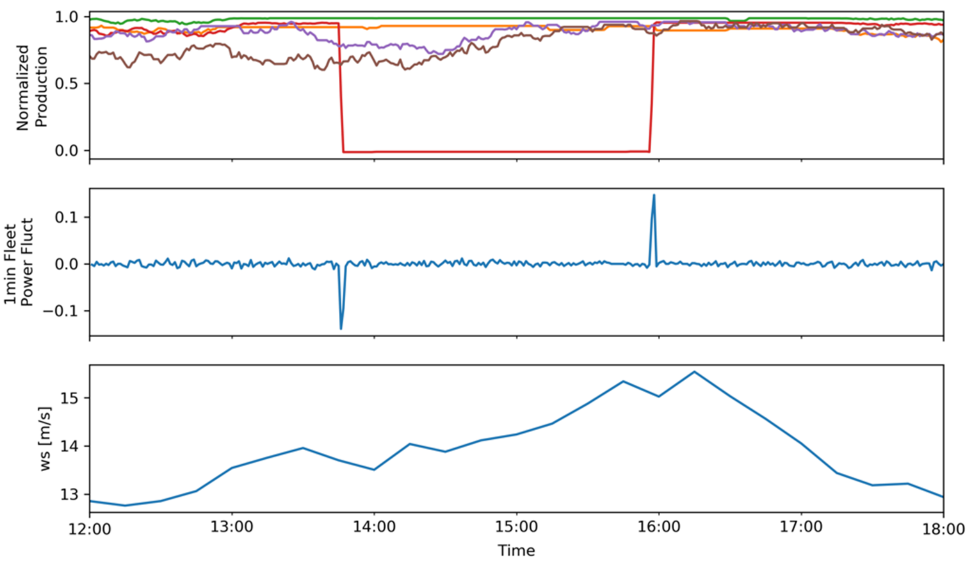


Figure 11. Extreme 1 min power fluctuation event on 2018-08-19; the top subplot shows generation from individual OWPPs; other subplots show fleet-level values.

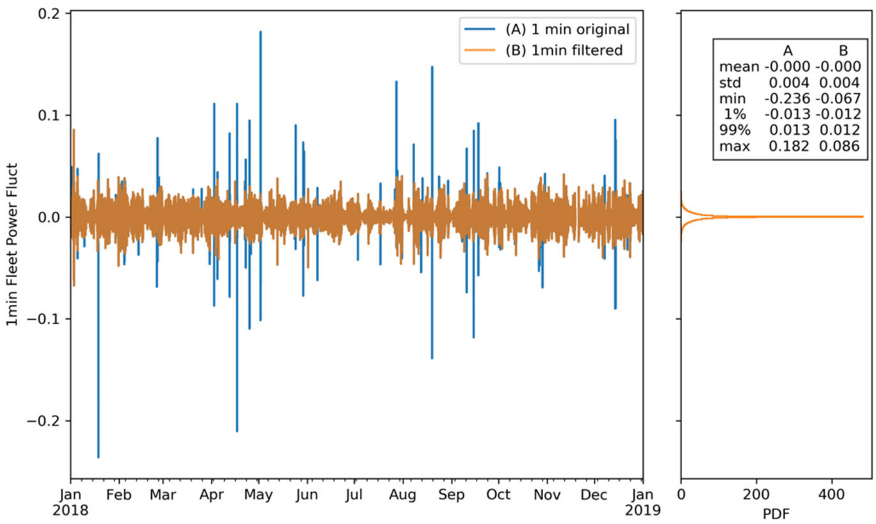


Figure 12. Measured 1 min fluctuations of the normalized fleet power: A: original dataset; B: after the removal of the control actions.

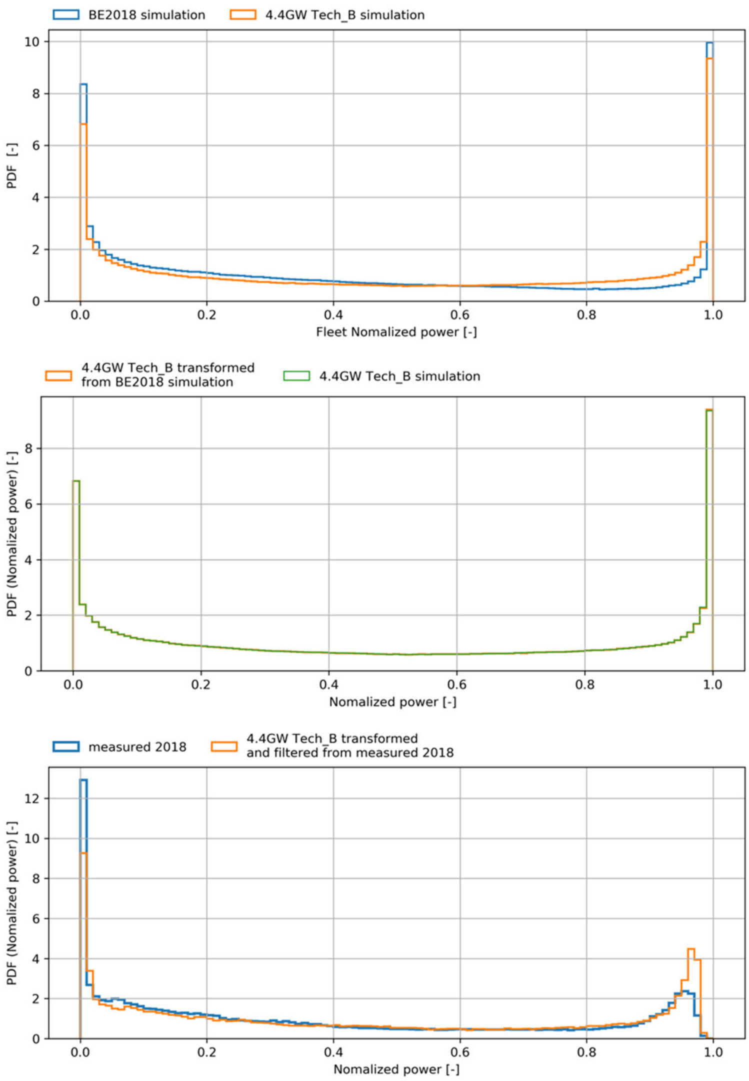


Figure 13. Result of the probability integral transformation for the 4.4 GW case with Tech B. Top: CorWind simulations for BE 2018 and BE 4.4 GW Tech B; middle: simulated BE 2018 transformed to BE 4.4 GW Tech B vs. the simulated BE 4.4 GW Tech B; bottom: measured 2018 and measured 2018 transformed to represent the BE 4.4 GW Tech B scenario.

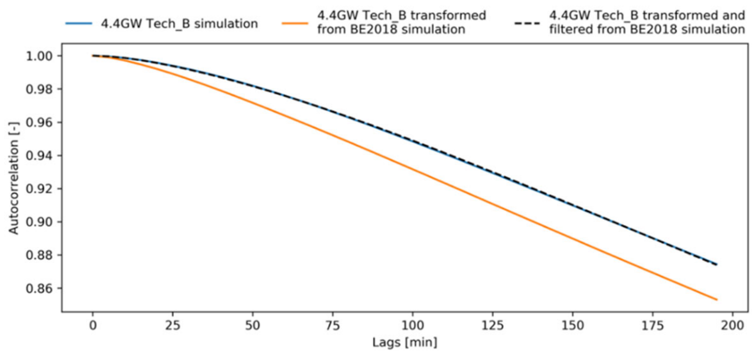
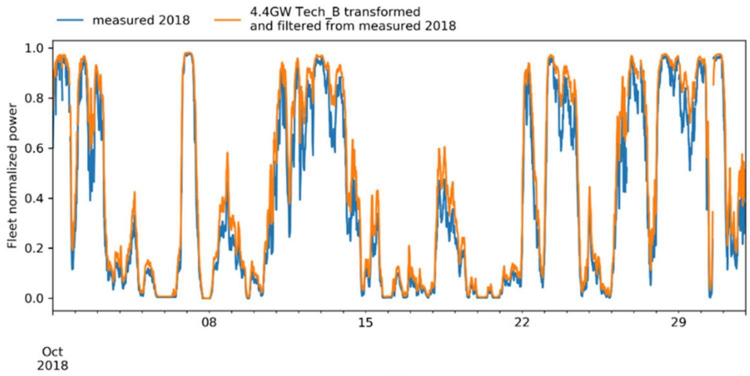


Figure 14. Autocorrelation of the resulting filtered time series for BE 4.4 GW Tech B. The orange line shows the result when only the PDF transformation is applied; the dashed line shows the result when also the filter considering temporal correlations has been applied.



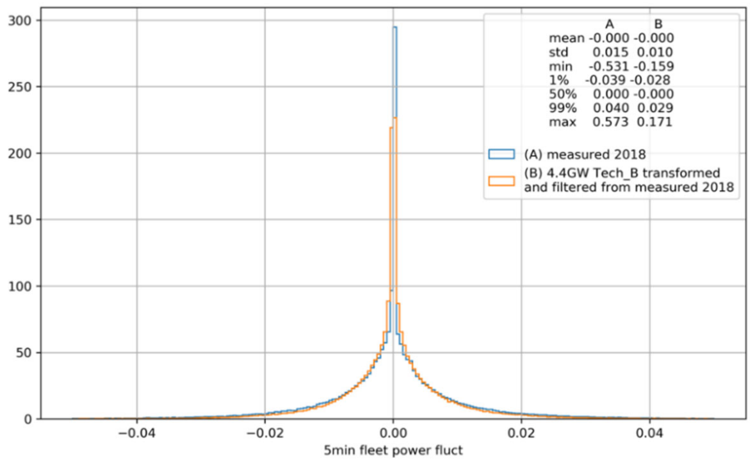


Figure 15. Example of the measured BE 2018 time series and the resulting filtered time series representing the 4.4 GW case with Tech B on the top, and comparison of 5 min power fluctuations in the bottom.

5.4.2 Representing forecast error changes

The forecasts measured from 2018 and 2019 are also processed to represent the expected reduction in fleet-level forecast errors shown in Chapter 10. This is achieved by using the reported reductions in forecast error SDs from BE2018 to the different simulated extended capacity scenarios. The forecast errors are first calculated for day-ahead, intraday and “Last” forecasts for the measured aggregated BE 2018 time series. Then these forecast errors are scaled down using the SD reduction factors from Chapter 10. The resulting filtered forecast errors are then combined to the filtered generation for the extended capacity scenario (transformed and filtered as described in the previous section) to find the forecast for the analysed scenarios.

6. Model validation

This chapter presents the measured data from Elia used in CorWind model validation in Section 6.1. Section 6.2 presents validation results on plant level and Section 6.3 on the aggregate offshore wind generation of Belgium. Validation considers statistics, such as capacity factors (CFs) and standard deviations (SDs), and probability density functions (PDFs). Ramp rates and behaviour during storms are also validated Section 6.4 looks also at the simulation of forecasts, and resulting forecast errors. Section 6.5 gives conclusions on the model validation.

6.1 Wind generation and wind speed measurements

6.1.1 Wind generation data

The measured generation data from the following OWPPs on 15 min resolution are used for model validation: Nobelwind, Belwind, Northwind, C_Power_1, C_Power_2 and C_power_3. The 15 min resolution data from 2015 to 2018 are used as the main validation dataset. Wind generation data is available also on 1 min resolution for 2018; these data are aggregated to 5 min resolution in model validation to assess CorWind's capability of modelling 5 min ramps. Some OWPPs do not have measurements covering the entire time range from 2015 and 2018; as much data as possible are used in model validation in plant level and aggregate level. Day-ahead, intraday and the latest ("Last") forecast errors are also available on 15 min resolution for each OWPP. The day-ahead, intraday and Last forecast horizons are aligned with Elia's forecast horizons and timing.

2019 data are not used in model validation due to reasons explained in Section 6.1.3.

6.1.2 Wind speed data

Wind speed data are available from Nobelwind, Belwind and Northwind and from C_Power. For C_power, it is not clear to which C_Power (1, 2 or 3) the wind speed data relates to; as the C_Power OWPPs are close by, the same wind speed data are used to represent wind speeds in each of the C_Power OWPPs. Wind speed data are available from 4 turbines per OWPP, from the 4 corners of each plant. For comparison to CorWind simulations, which are carried out per plant, mean of the 4 turbines is taken to represent the effective wind speed of the plant. Wind speeds and 10 min wind speed ramps are visualized for an example OWPP in Figure 16. The ramps show a non-Gaussian shape, with significant number of large down- and up-ramps. The same behavior was seen for all measured locations; for another example, wind speed ramps are shown in Figure 17. The distributional information on wind speeds was used in CorWind calibration, as similar behavior was seen in measured wind speeds from all OWPPs with data.

For the wind speed range where wakes have an impact (approx. below 14 m/s), the measured data is expected to include wake impacts. As wind speeds from CorWind simulations are given without wake impact (with wakes considered in the transformation from wind speed to generation), this difference is taken into account when comparing measured and simulated wind speeds. Generation data can be compared directly between the measurements and simulations. Figure 18 shows an example where the 15 min generation data and 10 min wind speed data (with linear interpolation) has been combined. When comparing to simulations, the values with wind speed between 5 and 15 m/s and generation 0 are not considered; this was done because even with storm protection considered, in this wind speed range generation should be above 0. Such data points were considered to be either measurement errors or indicating that the whole OWPP is unavailable (CorWind does not model unavailability). The time steps were marked as not available in the measured data. This was done for all OWPPs.

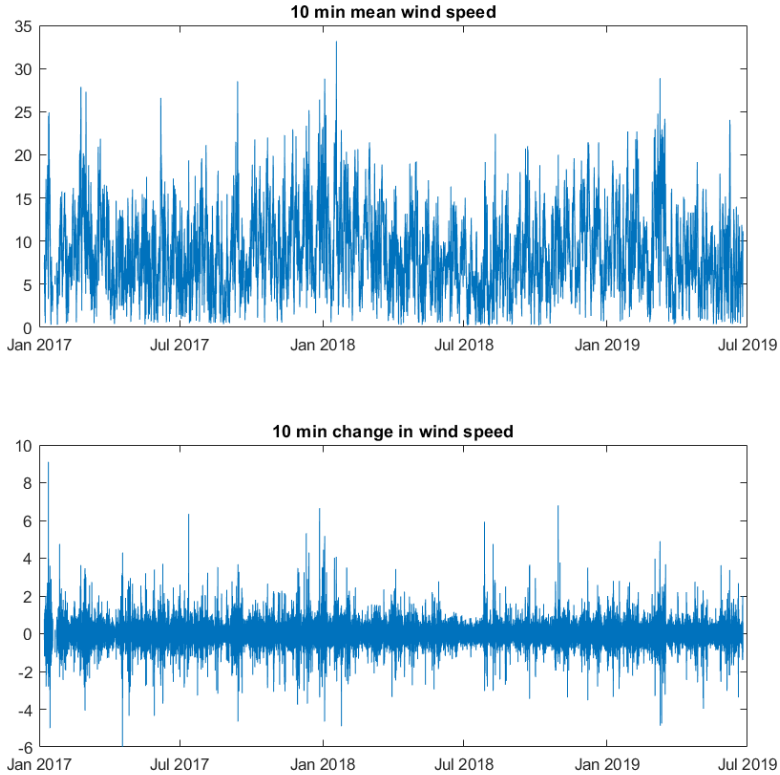


Figure 16. Measured wind speeds and 10 min wind speed ramps at an OWPP; 10 min resolution, mean of the 4 measured turbines.

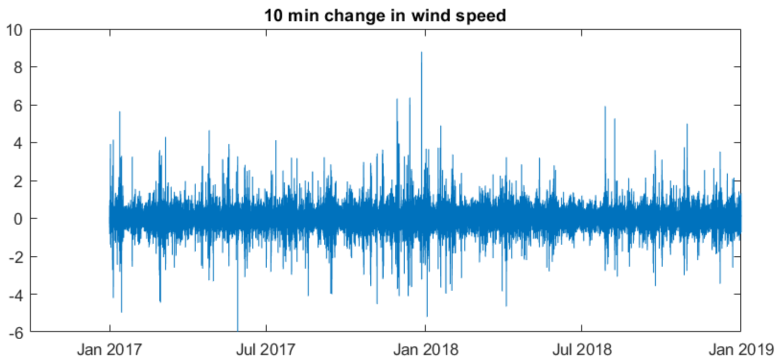


Figure 17. Measured 10 min wind speed ramps at an OWPP; 10 min resolution, mean of the 4 measured turbines.

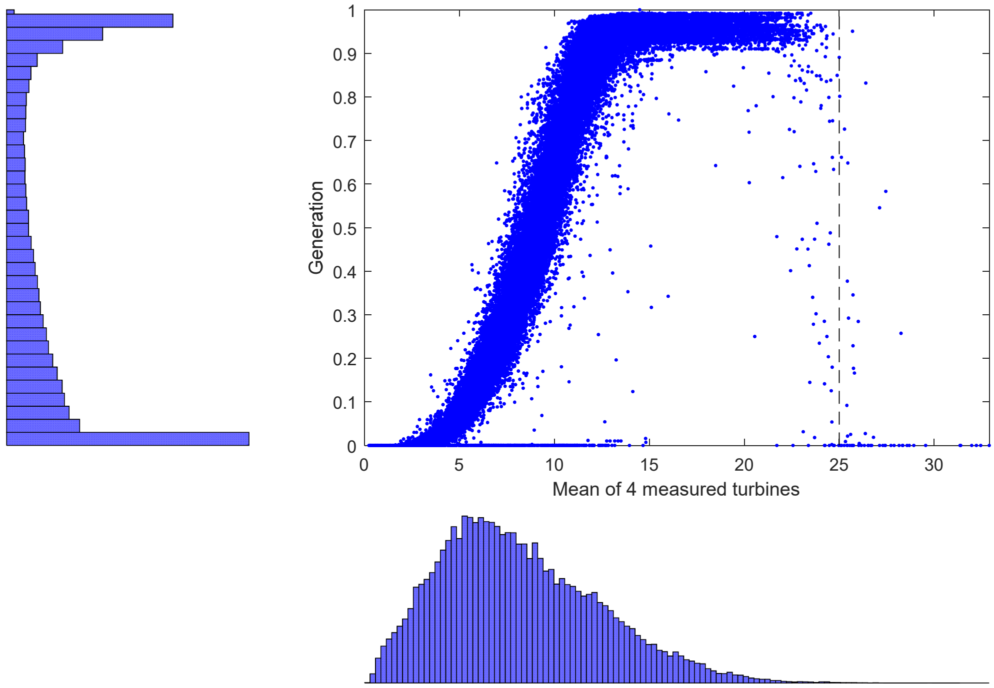


Figure 18. Wind speed (mean of the 4 measured turbines) and standardized generation scatter plot with histograms of an OWPP. Dashed line shown the turbine-level storm shutdown limit (25 m/s in this case).

6.1.3 About the time range of measurements for validation

The meteorological WRF data is available from 1982 until 2018. Thus, data after the end of 2018 cannot be simulated. As it cannot be simulated, it also cannot be compared to measured data in model validation; thus, only measurements until the end of 2018 are used when validating CorWind.

6.2 Plant level validation

6.2.1 Capacity factors

The differences in the measured and simulated capacity factors (CFs) for the six OWPPs in the validation are shown in Table 5. CorWind shows slightly higher CFs than measurements. The simulations assume 100 % availability for the OWPPs, so the tendency to get slightly higher CFs in the simulation is expected. Information about the availability of turbines in the different plants was not available.

Table 5. Differences in measured and simulated capacity factors.

	Difference
OWPP_1	-0.3%
OWPP_2	2.5%
OWPP_3	2.0%
OWPP_4	9.3%
OWPP_5	3.5%
OWPP_6	11.9%

6.2.2 Generation probability distributions

Simulated and measured generation probability density (PDF) is visualized for two example OWPPs in Figure 19 and Figure 20. The impact of assuming 100 % availability can be seen in the figures, as CorWind simulates exactly full generation when wind speed is favorable, whereas in measured data generation exactly at installed capacity is relatively rare. For both OWPPs, the peak in the PDF near 1 seems to be approximately at 0.95, suggesting on average unavailability of around 5 %. The PDFs for other OWPPs showed similar results. Standard deviations (SDs) of all the OWPPs are given in Table 6; it can be seen that simulated and measured SDs are similar.

Even though information about unavailability of turbines was not available, an option to roughly consider the unavailability in the simulations would be to multiple all simulated generation time series with a constant factor, e.g., 0.95. However, this would cause also the maximum generation to be reduced by 5 %; as can be seen in Figure 19, the measured data shows that sometimes the plant generation is at full installed capacity. Thus, the multiplication by 0.95 was not applied, and all results are given assuming 100 % availability of the plants. Post-processing of the simulated time series assuming 100 % availability can be done later, if required, to assess the impact of unavailability.

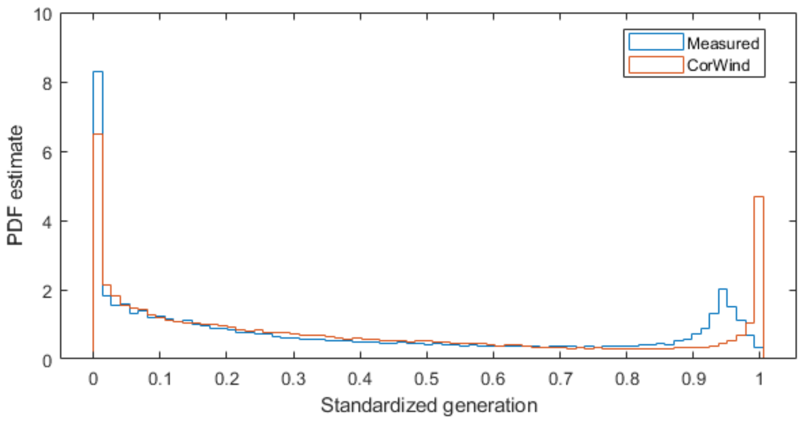


Figure 19. Generation PDF of the measured and simulated data for an example OWPP. Standardized generation is 1 when the OWPP is generating at installed capacity.

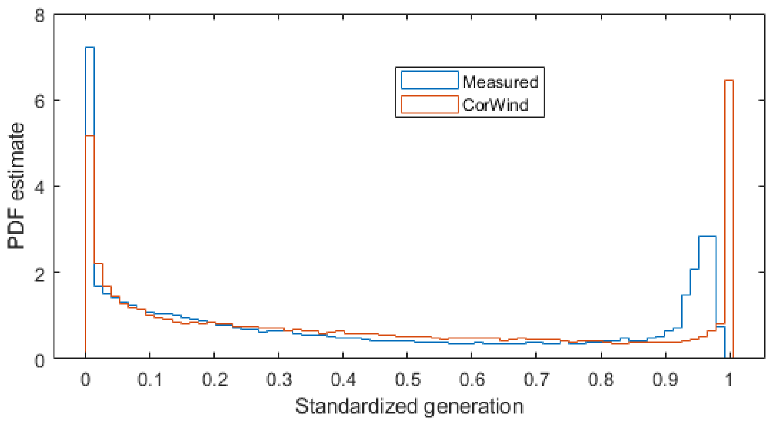


Figure 20. Generation PDF of the measured and simulated data for an example OWPP. Standardized generation is 1 when the OWPP is generating at installed capacity.

Table 6. Standard deviations of simulated and measured generation.

	Measured	CorWind	Difference
OWPP_1	0.343	0.340	-1.0%
OWPP_2	0.371	0.364	-2.1%
OWPP_3	0.357	0.349	-2.2%
OWPP_4	0.338	0.362	7.1%
OWPP_5	0.337	0.348	3.4%
OWPP_6	0.335	0.355	6.1%

6.2.3 Correlations

Correlations between generations from the OWPPs are shown Figure 21. It can be seen that generations from all OWPPs are highly correlated, with OWPPs very close by showing the highest correlation. The simulations show similar correlations compared to the measured data. These correlations are calculated as $\mathrm{Cor}(p_{t,i}\ ,\ p_{t,j})$, where $p_{t,i}$ is generation at plant *i* at time *t*. Both measured and simulated are 15 min resolution.

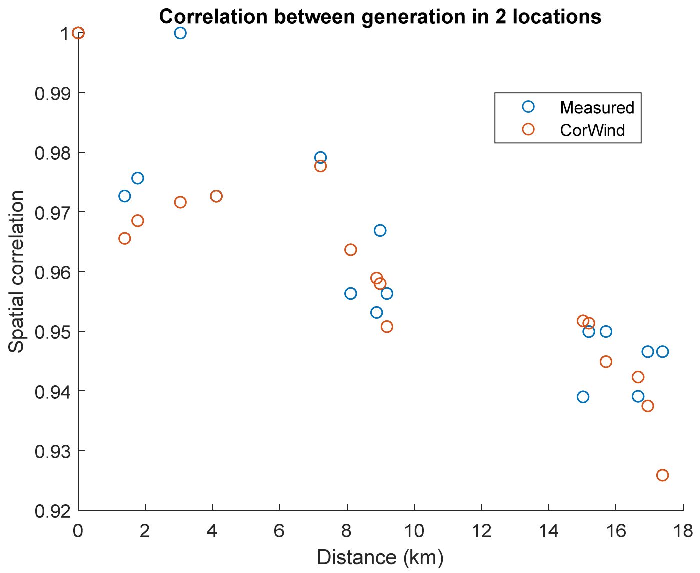


Figure 21. Correlation between generations from two OWPPs consider all combinations between the six OWPPs used in validation, plotted against the distance between the OWPPs.

6.2.4 Ramp behavior

SDs of 15 min ramp events are shown for the OWPPs in validation for the measured and simulated data in Table 7. The ramp SDs from CorWind and the measured data are similar.

Figure 22 shows how 15 min and 1 h ramps at the different OWPPs are correlated. It can be seen that the 15 min ramps have a relatively low correlation for the plants far away from each other; however, on the 1 h level, the correlation remains higher than 0.4 even for the plants around 18 km from each other. These correlation of ramps are calculated as $\mathrm{Cor}(\Delta p_{t,i}\ ,\ \Delta p_{t,j})$, where $\Delta p_{t,i}$ is ramp (change in generation) at plant *i* at time *t* during a time interval (e.g., 15 min). E.g., for 15 min ramps with 15 min resolution data, $\Delta_{15\mathrm{min}} p_{t,i} = p_{t,i} - p_{t-1,i}$, where $p_{t,i}$ is generation at 15 min resolution. $\Delta_{15\mathrm{min}} p_{t,i}$ is thus the difference between the mean generation values of two successive quarter hours. Hourly ramps are analysed on 15 min resolution, i.e., $\Delta_{\mathrm{hourly}} p_{t,i} = p_{t,i} - p_{t-4,i}$.

The different dependency of ramp correlation on distance for different ramp durations (15 min, 1 h) show that geographical smoothening is expected to have different impact of different time scales. It needs to be noted that even if correlation between ramps at two locations is zero, a ramp up or down can still happen simultaneously at the locations; but is less likely than in a case where the correlation is high.

Table 7. Standard deviation of 15 min ramps for measured and simulated data.

	Measured	CorWind	Difference
OWPP_1	0.0499	0.0456	-8.7%
OWPP_2	0.0470	0.0453	-3.6%
OWPP_3	0.0506	0.0459	-9.2%
OWPP_4	0.0469	0.0538	14.6%
OWPP_5	0.0468	0.0477	2.0%
OWPP_6	0.0486	0.0469	-3.5%

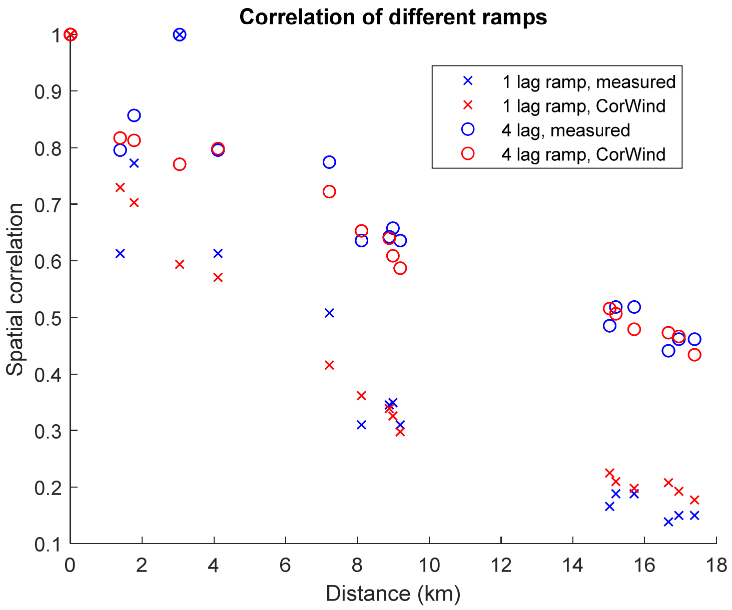


Figure 22. Correlations between 15 min (1 lag) and 1 h (4 lag) ramps for the measured and simulated data, plotted against distance between the OWPPs. 1 h ramp means difference in generation in 1 h on 15 min resolution (i.e., lag 4).

6.3 Aggregate generation validation

6.3.1 Capacity factor and generation probability distribution

CF and SD for the aggregate offshore wind generation of all the OWPPs in the validation (around 877 MW) are shown in Table 8. Both statistics are similar in the measured and simulated data. If availability would be around 95 %, the effective CF of the CorWind simulation would be 0.395, which is very close to the measured CF. Figure 23 shows that the simulated and measured PDFs are similar, expect for values between 0.85 and 1, which is expected as CorWind simulations do not consider unavailability.

Table 8. Capacity factor and standard deviation of the aggregate generation of the OWPPs in validation; all in standardized generation.

	CF	SD
Measured	0.399	0.350
CorWind	0.416	0.351

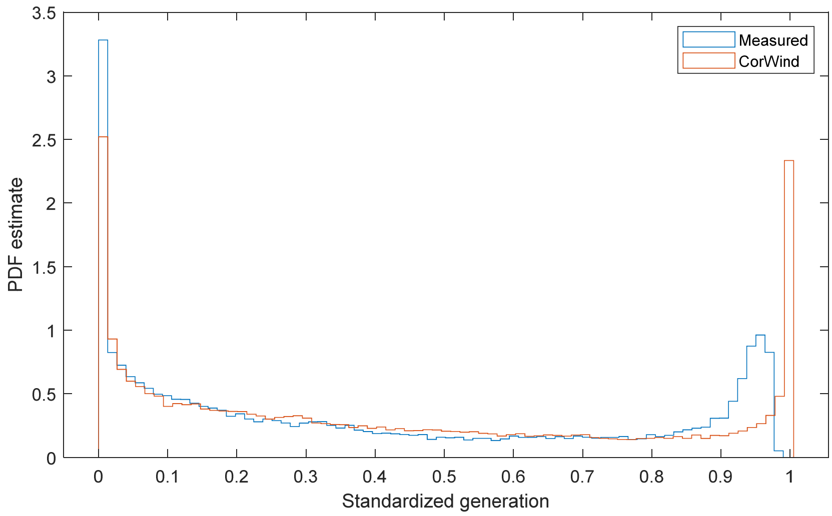


Figure 23. Generation PDF of the measured and simulated data for the aggregate of BE 2018 (the validation OWPPs).

6.3.2 Ramp behavior

The ramp behavior of aggregate offshore wind generation on 5 min resolution is shown in Figure 24 and Table 9. All statistics are similar in measured and simulated data; the minimum is lower in the simulated data compared to measurements; however, as the minimum is a single value over the entire period, and as the low percentiles are similar in measured and simulated data, this was not considered to be an issue

The ramp behavior on 15 min resolution is shown in Figure 25 and Table 10. The probability distributions of the ramps are similar for the measurements and simulations. It can be seen that the ramp SD is similar for measured and simulated data. Also the min and max ramps are similar. The most extreme percentiles (0.1 and 99.9) are somewhat closer to zero in the simulated data compared to the measurements, indicating that the simulation gives slightly lower likelihood for the most extreme ramps. However, measured data can include events which are not in simulations, such as cable faults or control actions, which can appear as ramp events. As the simulations do not include such events, it was not considered possible to assess the exact reason for the difference. The simulations are thus considered to be valid for simulating the ramp events; however, it needs to be noted that the likelihoods of the most extreme ramps may be slightly underestimated in the simulations.

Similar information is given for 1 h ramps (15 min resolution data) in Table 11 and Figure 26. The ramp SD and the minimum and maximum values are similar in simulated and measured data. The most extreme ramps are slightly underestimated in CorWind compared to the measured data.

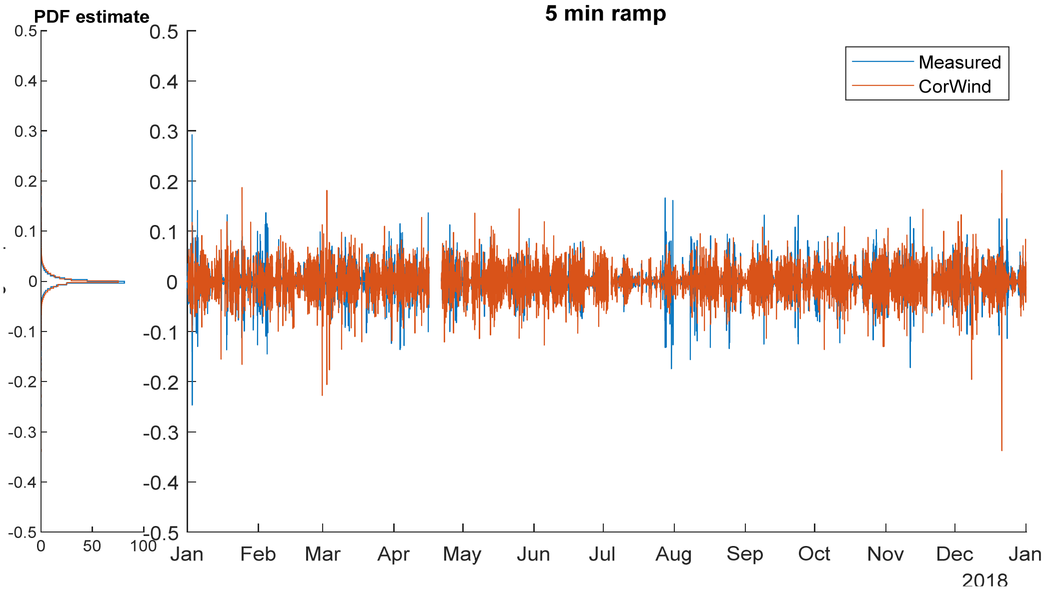


Figure 24. Time series plots of the simulated and measured 5 min ramps of the aggregate offshore wind generation, with estimated PDFs on the left.

Table 9. 5 min ramp statistics of the aggregate offshore wind generation (Prct = percentile).

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	0.000	0.013	-0.247	-0.089	-0.040	-0.020	0.020	0.040	0.081	0.292
CorWind	0.000	0.015	-0.338	-0.078	-0.043	-0.024	0.025	0.044	0.076	0.221

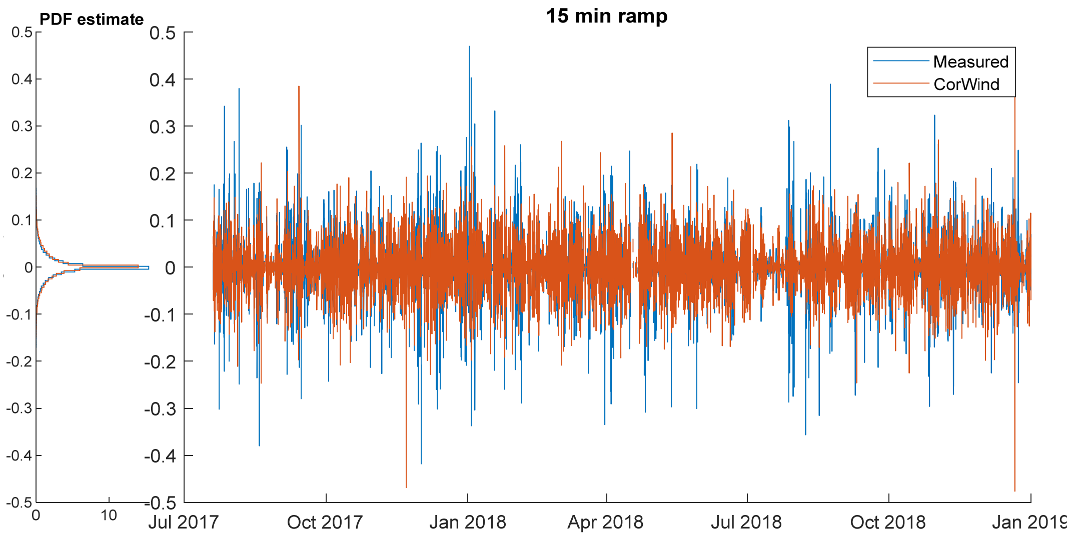


Figure 25. Time series plots of the simulated and measured 15 min ramps of the aggregate offshore wind generation, with estimated PDFs on the left.

Table 10. 15 min ramp statistics of the aggregate offshore wind generation (Prct = percentile)

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	0.000	0.033	-0.419	-0.226	-0.099	-0.048	0.049	0.101	0.205	0.470
CorWind	0.000	0.032	-0.477	-0.151	-0.091	-0.051	0.052	0.091	0.156	0.405

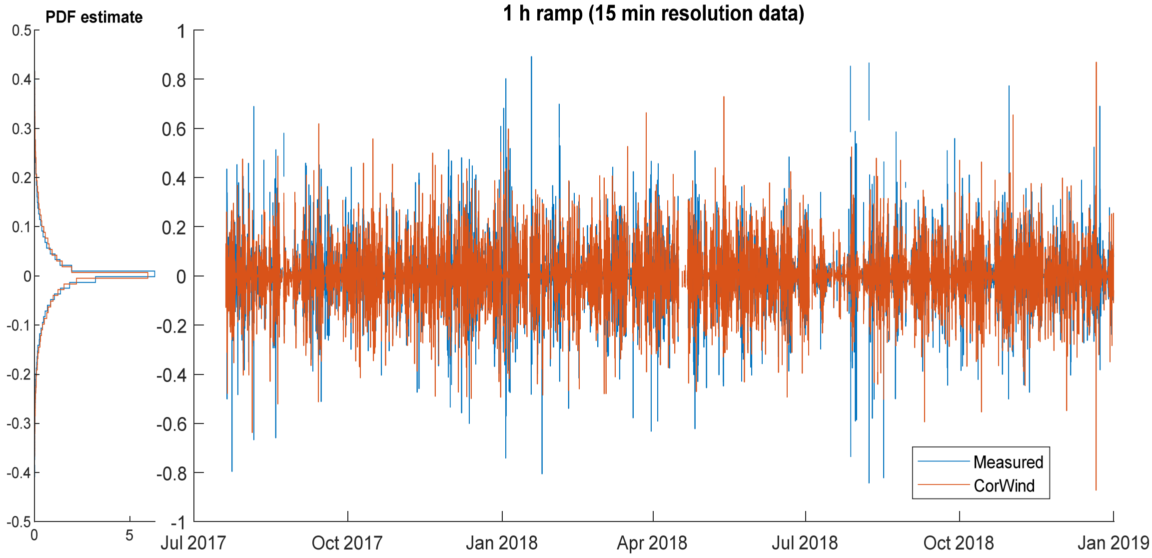


Figure 26. Time series plots of the simulated and measured 1h ramps of the aggregate offshore wind generation, with estimated PDFs on the left.

Table 11. 1 h ramp statistics of the aggregate offshore wind generation (Prct = percentile).

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	0.000	0.087	-0.843	-0.495	-0.255	-0.131	0.135	0.270	0.511	0.892
CorWind	0.000	0.089	-0.872	-0.432	-0.249	-0.143	0.148	0.257	0.429	0.870

6.3.3 Storm shutdown likelihoods

Scatter plots of the aggregate wind speeds and generations are shown in Figure 27. It can be seen that both the measured and simulated data reach points where the aggregate wind speed affecting the region is very high and the generation is low due to many, or even all, plants being in storm shutdown. The wind speed distributions of measured and simulated data seem different for wind speeds below 15 m/s; however, this is expected due to measurements including the wake effect and CorWind showing wind speeds without wake effects (in CorWind, wakes are considered when transforming wind speeds to generation, as explained in section 5.2). Considering the generation distribution, it needs to be noted that CorWind simulations assume 100 % availability.

The likelihoods of very high wind speed events are shown in Table 12 for the measured and simulated data. The likelihoods are similar; however, CorWind shows slightly less data points above 28 m/s. This may (at least partly) explain the slight underestimation of the extreme events described in Section 6.3.2. See Section 6.3.4 on how the very highest wind speeds are modelled in CorWind.

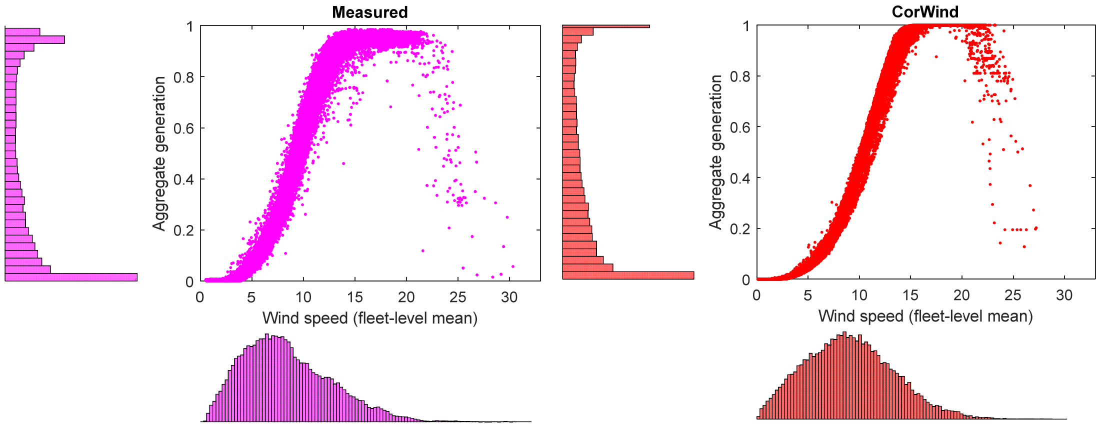


Figure 27. Scatter plots of fleet-level wind speeds (averages weighted by installed OWPP capacities) and aggregate generation of the studied OWPPs.

Table 12. Likelihoods of high wind speed events.

Fleet-level mean wind speed above (m/s)	Measured (%)	CorWind (%)
18	2.312	2.642
20	0.815	0.900
22	0.292	0.303
24	0.125	0.082
26	0.023	0.028
28	0.009	0.004
30	0.001	0.000

Data from 2017-2018, when all plants have recordings (only simulations of those time steps where measurements are available are considered).

6.3.4 Modelling the probabilities of very high wind speeds

Based on the measured wind speeds from the Belgian OWPPs, the very highest wind speeds from the mesoscale WRF model are scaled up by 8 %, as shown in Figure 28. This is done to better match the probabilities of very high wind speeds seen in the measured data. The high wind speed percentiles and maximum 10 min wind speeds for the OWPPs in the validation are shown in Table 13 for the measured data, WRF directly and CorWind simulation. It can be seen that WRF shows lower high percentiles and maximums compared to the measured data; the CorWind simulation (with the 8 % scale up) shows on average similar percentiles and maximums compared to the measurements; individual OWPPs show some differences compared to CorWind (results for individual OWPPs are reported to Elia, but are not shown in this report). Note that the maximums in CorWind are not directly 8 % higher than the maximums in WRF, because CorWind includes also the stochastic fluctuation simulations that are added to the mesoscale WRF data (see section 5.1).

The need to scale up the highest WRF wind speeds to represent the actual maximum wind speeds is noted in literature [13], and it was thus considered justifiable in the modelling. The results in Table 12 and Table 13 show that the resulting CorWind simulations represent well the likelihoods of very high wind speeds compared to measured data (Table 12 includes the 8 % increase of the highest mesoscale wind speed).

Table 13. Very high wind speed statistics for the OWPPs with wind speed measurements.

	Percentile 99.9			Percentile 99.99			Max		
	Measured	**WRF directly**	**CorWind**	**Measured**	**WRF directly**	**CorWind**	**Measured**	**WRF directly**	**CorWind**
Mean of individual OWPPs	25.2	22.8	23.9	28.2	25.4	27.9	31.3	26.2	30.0

The statistics are based on 10 min mean wind speeds. Data from 2015-2018, per OWPP as much data used as measurements are available (only simulations of those time steps where measurements are available are considered). For the measured data, the mean values of the 4 measured turbines per OWPP were used (to represent plant-level wind speeds). The CorWind runs include the 8 % hi-wind scale up.

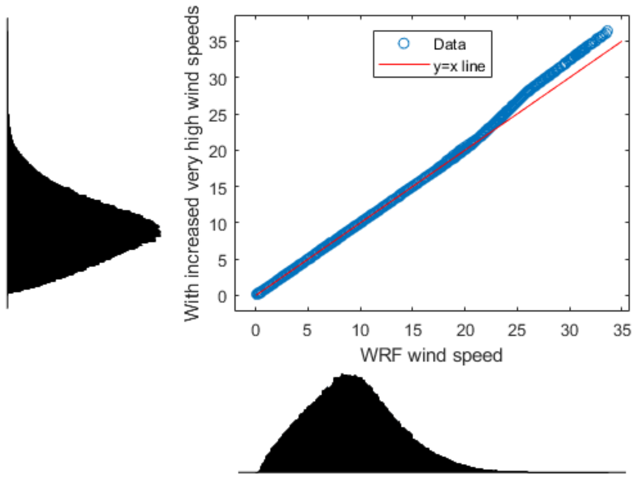


Figure 28. Increase of the highest mesoscale WRF wind speeds for an example location. Wind speeds over 26 m/s are increased by 8 %, with linear increase starting at 20 m/s. The plot includes the entire 37 years of data.

6.4 Forecast errors

6.4.1 Day-ahead forecasts

PDF and statistics of the measured and simulated day-ahead forecast errors are shown in Table 14 and Figure 29. Although aggregate statistics are shown, each OWPP is simulated in CorWind. The forecast SD is slightly lower in measured data compared to CorWind; however, the percentiles and the min and max forecast errors are similar.

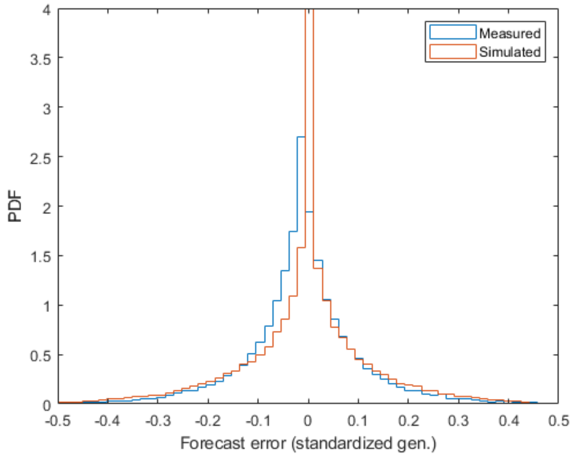


Figure 29. Measured and simulated day-ahead forecast error PDFs; aggregate of all the OWPPs belonging to validation (BE 2018). Data from 2017-2018, when all plants have recordings (only simulations of those time steps where all measurements are available are considered).

Table 14. Day-ahead forecast error statics for the aggregate of the validation OWPPs (BE 2018).

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	-0.010	0.118	-0.824	-0.547	-0.349	-0.204	0.183	0.326	0.526	0.815
CorWind	-0.007	0.135	-0.870	-0.595	-0.403	-0.245	0.218	0.359	0.522	0.809

Data from 2017-2018, when all plants have recordings (only simulations of those time steps where all measurements are available are considered).

6.4.2 Intraday forecasts

PDF and statistics of the measured and simulated intraday forecast errors are shown in Figure 30 and Table 15. As with the day-ahead forecast, CorWind shows slightly higher SD; however, the percentiles and min and max values are similar to the measured data.

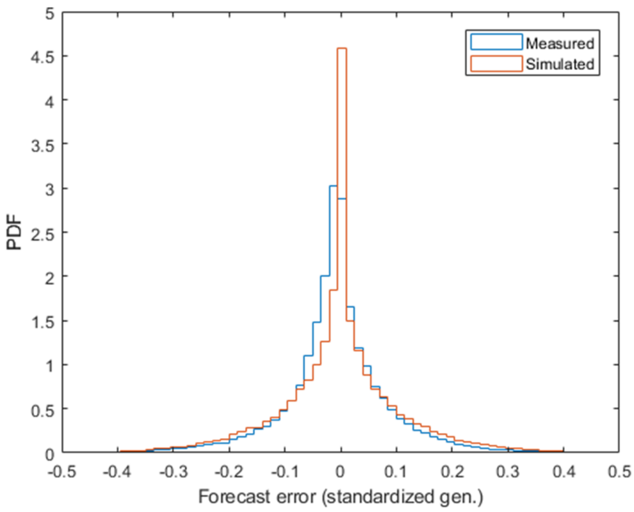


Figure 30. Measured and simulated intraday forecast error PDFs; aggregate of all the OWPPs belonging to validation (BE2018). Data from 2017-2018, when all plants have recordings (only simulations of those time steps where all measurements are available are considered).

Table 15. Intraday forecast error statics for the aggregate of the validation OWPPs (BE 2018).

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	-0.007	0.097	-0.735	-0.485	-0.299	-0.167	0.149	0.269	0.469	0.759
CorWind	-0.002	0.112	-0.872	-0.473	-0.322	-0.192	0.188	0.316	0.487	0.638

Data from 2017-2018, when all plants have recordings (only simulations of those time steps where all measurements are available are considered).

6.4.3 Latest forecasts

The "Last" forecasts in Elia's data denote the latest forecast available for each time step (15 min resolution). Table 16 and Figure 31 compare the measure and simulated latest forecast errors. CorWind shows somewhat lower SD and the most extreme percentiles indicate lower forecast errors in CorWind compared to measurements. However, the PDF looks quite similar for measured and simulated data, and the min and max values are similar. Comparing to Table 15, it can be seen that:

- For the measurement, "Last" shows higher min and max forecast errors compared to Intraday;
- For CorWind, "Last" shows a higher max forecast error compared to Intraday.

It is noted that the measured data shows relatively small decrease in forecast error SD from Intraday to "Last". In CorWind, this difference is larger.

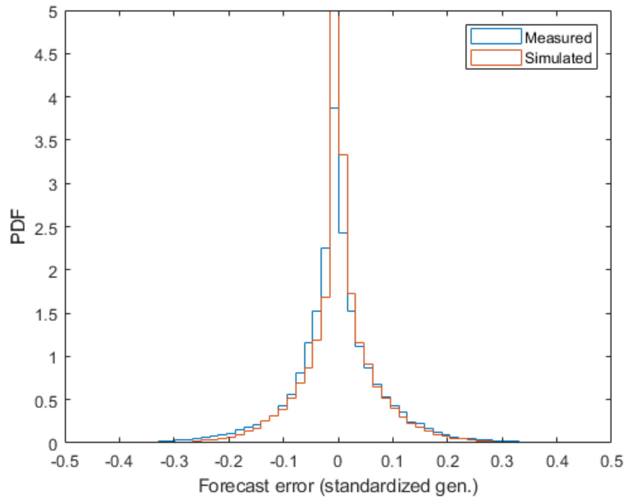


Figure 31. Measured and simulated latest ("Last") forecast error PDFs; aggregate of all the OWPPs belonging to validation (BE2018). Data from 2017-2018, when all plants have recordings (only simulations of those time steps where all measurements are available are considered).

Table 16. "Last" forecast error statics for the aggregate of the validation OWPPs (BE 2018).

	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	-0.005	0.087	-0.795	-0.450	-0.261	-0.146	0.135	0.244	0.427	0.765
CorWind	0.001	0.071	-0.798	-0.334	-0.203	-0.117	0.118	0.208	0.346	0.683

Data from 2017-2018, when all plants have recordings (only simulations of those time steps where all measurements are available are considered).

6.5 Conclusion on the model validation

The model validation shows that CorWind is able to model the generation time series of the existing offshore wind power plants in Belgium (the BE2018 OWPPs). It is thus considered valid for modelling the MOG II capacity extension.

The capacity factors predicted by CorWind are slightly larger because the simulations assume 100 % availability. However, availability is not applied as a static factor (e.g., 0.95), because it would change other statistics that are well modelled (e.g., SD). In addition:

- Full installed capacity ramps are seen in data during a few hours;
- The availability factor in the future is unknown, also but not only for the additional installations;
- Overplanting is not to be excluded for the additional installations.

Therefore, it would not be appropriate to include an availability factor for the purposes of this study, nor to post-process the results which would artificially decrease the evaluation of extreme events.

Statistics of ramps are similar for the measured and simulated data. There is a slight underestimation of the 0.1 and 99.9 percentiles; this means that the likelihoods of the events rarer than the 0.1 and 99.9 percentile range may be underestimated in CorWind. However, the simulated data are not adjusted, because the reason for these differences cannot be clearly identified. This needs to be noted when assessing the results of the extended capacity simulations.

The highest wind speed from the mesoscale WRF data are increased by 8 %. This is justified looking at the measured wind speed data, and based on literature on the expected underestimation of maximum wind speeds in WRF. The resulting CorWind runs model well the likelihoods of very high wind speeds. The use of 37 years of meteorological data in the simulation of the extended capacity ensures that a wide range of extreme events are simulated.

For forecast errors, CorWind shows similar statistics compared to measured data. The SDs differ slightly for day-head and intraday; however, percentiles and min and max values are similar. For the “Last” forecast errors, CorWind shows somewhat lower general uncertainty than the measured data; however, min and max values are similar to measurements. In general, forecast errors are more difficult to simulate, as the target is not to replicate the variability due to weather, but to try to represent the forecasts by Elia’s forecast provider. For this reason, the results presented for forecasts and forecast errors for the extended capacity scenarios need to be taken as representing average changes in the forecast errors resulting from different geographical installation distributions and storm shutdown technologies. The actual simulated forecast and forecast error values for an individual event are stochastic, and can be high or low due to randomness.

7. Basic statistics for the scenarios

This chapter presents CFs and SDs for all the scenarios. PDFs are also shown to visualise differences between the scenarios.

7.1 Capacity factors and standard deviations

CFs and SDs of the aggregate generation in the different scenarios are given in Table 17.
It can be seen that the aggregate CF of the fleet is expected to increase from BE 2018 towards the 4.4 GW scenarios, with Tech B showing significant increase compared to Tech A; this leads to more annual offshore generation with the same installed capacity.
The SD increases only slightly towards the 4.4 GW scenarios, with Tech B showing marginally higher SD than Tech A. The 4.4 GW Tech A and B mixture scenarios shows all statistics in between the full Tech A and B scenarios. As storm events are rare, there are only very small difference between the different storm shutdown types for these statistics.
Statistics for the additional installations (instead of the full fleet) are given in Appendix A: CFs and SDs of the additional installations.

Table 17. Capacity factors and standard deviations.

			CF	SD	CF compared to BE 2018	SD compared to BE 2018
BE 2018 (877 MW)			0.420	0.346	100%	100%
2.3 GW			0.430	0.354	103%	102%
3.0 GW	**Tech A**	**25 m/s**	0.436	0.353	104%	102%
		Moderate	0.436	0.353	104%	102%
		Deep	0.437	0.353	104%	102%
	Tech B	**25 m/s**	0.453	0.353	108%	102%
		Moderate	0.454	0.354	108%	102%
		Deep	0.455	0.354	108%	102%
4.0 GW	**Tech A**	**25 m/s**	0.447	0.353	106%	102%
		Moderate	0.448	0.354	107%	102%
		Deep	0.448	0.354	107%	102%
	Tech B	**25 m/s**	0.480	0.356	114%	103%
		Moderate	0.482	0.357	115%	103%
		Deep	0.482	0.357	115%	103%
4.4 GW	**Tech A**	**25 m/s**	0.449	0.354	107%	102%
		Moderate	0.450	0.354	107%	102%
		Deep	0.450	0.355	107%	102%
	Tech B	**25 m/s**	0.485	0.357	116%	103%
		Moderate	0.487	0.358	116%	103%
		Deep	0.488	0.358	116%	103%
	Tech A/B	**25 m/s**	0.474	0.355	113%	103%
		Moderate	0.475	0.356	113%	103%
		Deep	0.476	0.356	113%	103%

From aggregate standardized generation of the 37 years of simulations on 5 min resolution. Tech A/B has mixture of Tech A and Tech B (see Section 4.3). Availability of 100 % is assumed.

7.2 Variability

PDFs of the 4.4 GW Tech A and Tech B scenario generations are shown in Figure 32, with BE 2018 shown for comparison. The Tech B scenarios show increased likelihoods of generation being around 75 % to 100 % of installed capacity and reduced likelihoods of low generation; these differences lead to the increased CF seen in Table 17. Figure 33 shows that storm shutdown type has very limited impact of the generation PDF, as expected (storm events are rare).

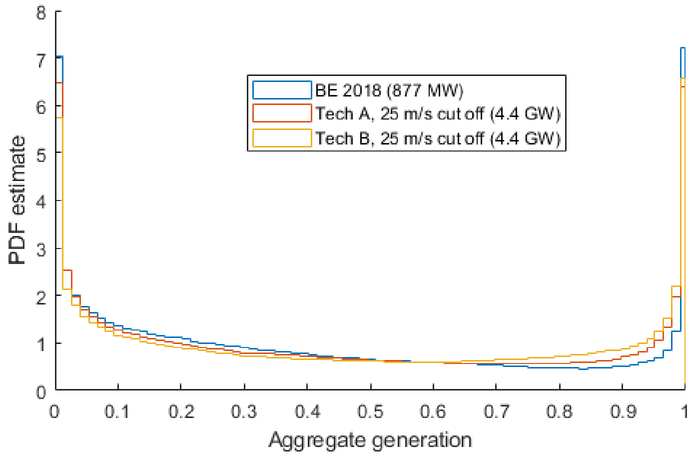


Figure 32. Generation PDFs for BE2018 and 4.4 GW Tech A and Tech B scenarios with direct 25 m/s cut off (standardized generation).

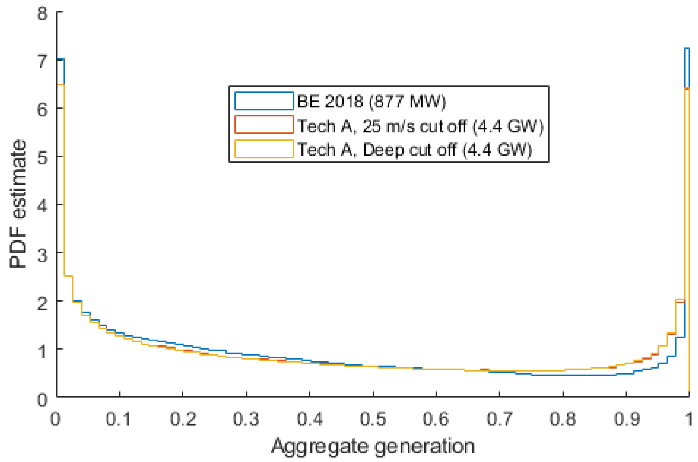


Figure 33. Generation PDFs for BE2018 and 4.4 GW Tech A scenarios with direct 25 m/s and Deep storm shutdown type (standardized generation).

8. Statistical analysis of ramping events

This chapter presents the results on ramping events for the studied scenarios; the scenarios are presented in Section 4.3. 37 years, from 1982 to 2018, are simulated on 5 min resolution. Each OWPP is simulated, although only aggregated ramp results are reported. All results are given based on 5 min resolution data.

The first section compares the scenarios in standardized generation, as the impact of geographical smoothening is easier to see when all data are standardized. The further sections show results in GW.

It is to be noted that the storm events are not filtered out of the data, which means that the ramps that occur during the cut-out and the cut-in phases of storms is included in the statistics presented. In order to isolate the ramp events which are not due to storms, section 8.4 shows the same results but only for those days when the maximum daily wind speeds is below 20 m/s.

Note that when comparing the 2.3 GW part (existing + planned OWPPs) and the 2.1 GW of additional installations to reach the 4.4 GW of offshore wind, the 2.3 GW part is referred to as “existing” and 2.1 GW as “additional” in the figures.

8.1 Results in standardized generation

8.1.1 5 min ramps

Figure 34 shows the 5 min ramp PDFs for some example scenarios. It can be seen that the 5 min ramps expressed in standardized generation decrease from BE 2018 towards the 4.4 GW scenario. The PDFs of the different storm shutdown types show very similar PDFs for the 4.4 GW Tech A scenario; this is because storm events are relatively rare, and differences between the different shutdown types impact only the most extreme tails of the distributions.

5 min ramp statistics of all the scenarios are shown in Table 18. The ramp SD decreases significantly from BE 2018 towards the 4.4 GW scenarios. Tech A and B show similar ramp statistics; however, ramps in the Tech B scenarios are slightly higher. The mixture of Tech A and Tech B shows ramp statistics in-between the fully Tech A and fully Tech B scenarios. The Deep and Moderate storm shutdown types show decreased likelihoods for the most extreme ramps compared to the 25 direct cut-off.

Statistics for the additional installations (instead of the full fleet) are given in Appendix B: 5 min ramp statistics for the additional installations. The results show that the most significant reduction in aggregate ramps is only observed when considering both the 2.3 GW of installations and the additional installations towards 4.4. GW.

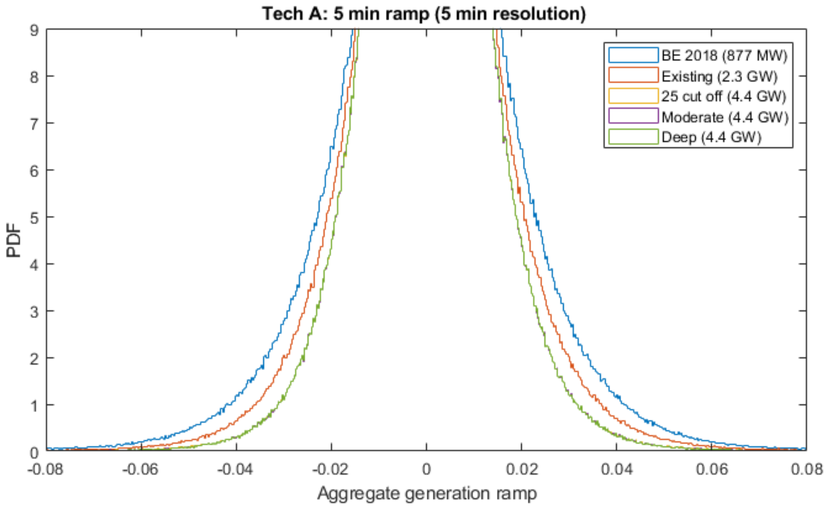


Figure 34. 5 min ramp PDFs for example scenarios (standardized generation). The 4.4 GW scenarios with different storm shutdown types are almost fully on top of each other. "Existing" refers to the 2.3 GW of installations.

Table 18. 5 min ramps statistics (standardized generation).

								Compared to BE 2018		
			SD	Prct 0.01	Prct 0.1	Prct 99.9	Prct 99.99	SD	Prct 0.1	Prct 99.9
BE 2018 (877 MW)			0.015	-0.130	-0.078	0.078	0.136	100%	100%	100%
2.3 GW			0.013	-0.097	-0.061	0.063	0.097	81%	78%	82%
3.0 GW	Tech A	25 m/s	0.012	-0.097	-0.056	0.058	0.098	76%	72%	75%
		Moderate	0.012	-0.086	-0.055	0.057	0.090	75%	71%	74%
		Deep	0.012	-0.084	-0.055	0.057	0.087	75%	71%	73%
	Tech B	25 m/s	0.012	-0.100	-0.057	0.058	0.099	76%	73%	75%
		Moderate	0.012	-0.089	-0.056	0.057	0.090	75%	72%	74%
		Deep	0.012	-0.085	-0.055	0.057	0.088	75%	71%	73%
4.0 GW	Tech A	25 m/s	0.010	-0.096	-0.050	0.052	0.092	68%	64%	66%
		Moderate	0.010	-0.075	-0.048	0.050	0.079	67%	62%	64%
		Deep	0.010	-0.071	-0.047	0.049	0.074	66%	61%	63%
	Tech B	25 m/s	0.011	-0.102	-0.052	0.052	0.099	69%	67%	68%
		Moderate	0.010	-0.081	-0.050	0.050	0.081	68%	64%	65%
		Deep	0.010	-0.075	-0.049	0.050	0.077	67%	63%	64%
4.4 GW	Tech A	25 m/s	0.011	-0.102	-0.050	0.052	0.098	69%	65%	68%
		Moderate	0.010	-0.077	-0.048	0.050	0.080	67%	62%	65%
		Deep	0.010	-0.072	-0.048	0.050	0.075	67%	62%	64%
	Tech B	25 m/s	0.011	-0.110	-0.054	0.054	0.107	70%	69%	69%
		Moderate	0.011	-0.083	-0.051	0.051	0.084	68%	65%	66%
		Deep	0.010	-0.076	-0.050	0.050	0.079	68%	64%	65%
	Tech A/B	25 m/s	0.011	-0.106	-0.052	0.053	0.104	69%	68%	68%
		Moderate	0.010	-0.081	-0.050	0.051	0.082	68%	64%	65%
		Deep	0.010	-0.075	-0.049	0.050	0.077	68%	63%	64%

8.1.2 15 min ramps

Figure 35 shows 15 min ramp PDFs for some example scenarios. It can be seen that the 15 min ramps expressed in standardized generation decrease from BE 2018 towards the 4.4 GW of installations. The PDFs of the different storm shutdown types show very similar PDFs; this is because storm events are relatively rare, and differences between the different shutdown types impact only the most extreme tails of the distributions.

15 min ramps statistics of all the scenarios are shown in Table 19. The ramp SD decreases significantly from BE 2018 towards the 4.4 GW scenarios. Tech A and B show similar ramp statistics; still, ramps in the Tech B scenarios are slightly higher. The mixture of Tech A and Tech B shows ramp statistics between the 100% Tech A and 100% Tech B scenarios. The Deep and Moderate storm shutdown types show decreased likelihoods for the most extreme ramps compared to the 25 direct cut-off. It can be seen that the ramp distributions tend to be skewed slightly to the right; this means that there are more extreme up-ramps than down-ramps. This is partly explained by the storm shutdown types only affecting the shutdown and not the restart operation during storm (Section 9.4 provides more information); however, even for non-storm days, up-ramps show slightly higher probability than similar magnitude down-ramps (see Section 8.4).

Statistics for the additional installations (instead of the full fleet) are given in Appendix C: 15 min ramp statistics for the additional installations. The results show that the most significant reduction in aggregate ramps is only observed when considering both the 2.3 GW of installations and the additional installations towards 4.4. GW.

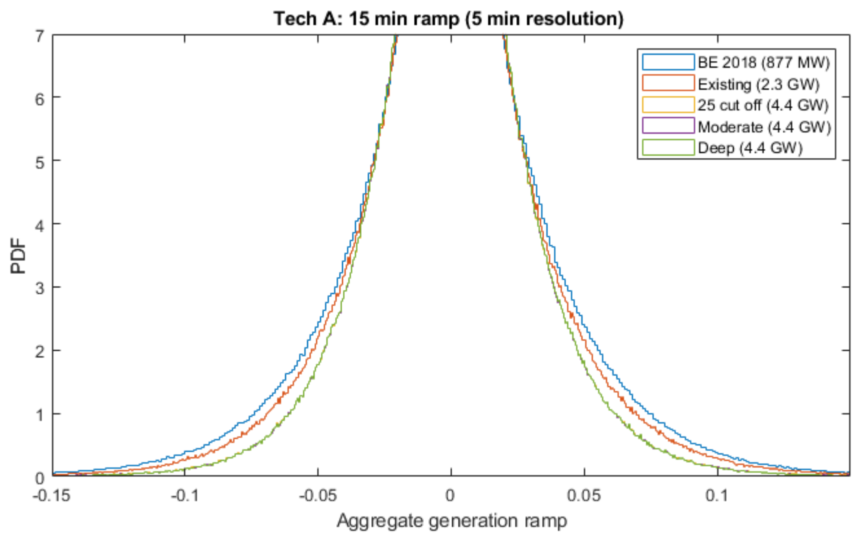


Figure 35. 15 ramp PDFs for example scenarios (standardized generation). The 4.4 GW scenarios with different storm shutdown types are almost fully on top of each other. "Existing" refers to the 2.3 GW of installations.

Table 19. 15 min ramps (5 min resolution) statistics (standardized generation).

			SD	Prct 0.01	Prct 0.1	Prct 99.9	Prct 99.99	Compared to BE 2018 SD	Compared to BE 2018 Prct 0.1	Compared to BE 2018 Prct 99.9
BE 2018 (877 MW)			0.035	-0.268	-0.171	0.178	0.291	100%	100%	100%
2.3 GW			0.031	-0.224	-0.147	0.156	0.237	88%	86%	87%
3.0 GW	**Tech A**	**25 m/s**	0.029	-0.222	-0.135	0.145	0.232	81%	79%	81%
		Moderate	0.029	-0.197	-0.132	0.142	0.218	81%	77%	80%
		Deep	0.029	-0.194	-0.131	0.141	0.214	81%	77%	79%
	Tech B	**25 m/s**	0.029	-0.226	-0.137	0.144	0.232	82%	80%	81%
		Moderate	0.029	-0.203	-0.134	0.141	0.219	81%	78%	79%
		Deep	0.029	-0.197	-0.132	0.139	0.214	81%	77%	78%
4.0 GW	**Tech A**	**25 m/s**	0.026	-0.210	-0.123	0.130	0.221	74%	72%	73%
		Moderate	0.026	-0.179	-0.118	0.125	0.198	73%	69%	70%
		Deep	0.026	-0.170	-0.117	0.123	0.186	73%	68%	69%
	Tech B	**25 m/s**	0.027	-0.222	-0.128	0.131	0.229	75%	75%	73%
		Moderate	0.026	-0.188	-0.122	0.125	0.199	74%	71%	70%
		Deep	0.026	-0.176	-0.120	0.123	0.188	73%	70%	69%
4.4 GW	**Tech A**	**25 m/s**	0.026	-0.224	-0.125	0.131	0.230	74%	73%	74%
		Moderate	0.026	-0.181	-0.119	0.126	0.201	73%	70%	71%
		Deep	0.026	-0.170	-0.117	0.124	0.187	73%	69%	69%
	Tech B	**25 m/s**	0.027	-0.236	-0.131	0.134	0.245	76%	77%	75%
		Moderate	0.026	-0.191	-0.124	0.127	0.206	74%	73%	71%
		Deep	0.026	-0.179	-0.121	0.124	0.191	74%	71%	70%
	Tech A/B	**25 m/s**	0.027	-0.223	-0.129	0.132	0.234	75%	75%	74%
		Moderate	0.026	-0.187	-0.122	0.125	0.202	74%	71%	70%
		Deep	0.026	-0.177	-0.120	0.123	0.189	73%	70%	69%

8.1.3 1 h ramps

Figure 36 shows the 1h ramp PDFs for some example scenarios. It can be seen that the 1 h ramps expressed in standardized generation decrease from BE 2018 towards the 4.4 GW of installations; however, the relative decrease in variability is less than for the 5 min and 15 min ramps. The PDFs of the different storm shutdown types show very similar PDFs for the 4.4 GW scenario.

1h ramp statistics of all scenarios are shown in Table 20. The ramp SD decreases significantly from BE 2018 towards the 4.4 GW scenarios. Tech A and B show similar ramp statistics; however, ramps in the Tech B scenarios are slightly higher. The mixture of Tech A and Tech B shows ramp statistics in between the fully Tech A and fully Tech B scenarios. Unlike for the 5 and 15 min ramps, the Deep and Moderate storm shutdown types show only marginally decreased likelihoods for the most extreme ramps compared to the 25 direct cut-off. It can be seen that the ramp distributions tend to be skewed slightly to the right; this means that there are more extreme up-ramps than down-ramps.

Statistics for the additional installations (instead of the full fleet) are given in Appendix D: 1h ramp statistics for the additional installations. The results show that the most significant reduction in aggregate ramps is only observed when considering both the 2.3 GW of installations and the additional installations towards 4.4. GW.

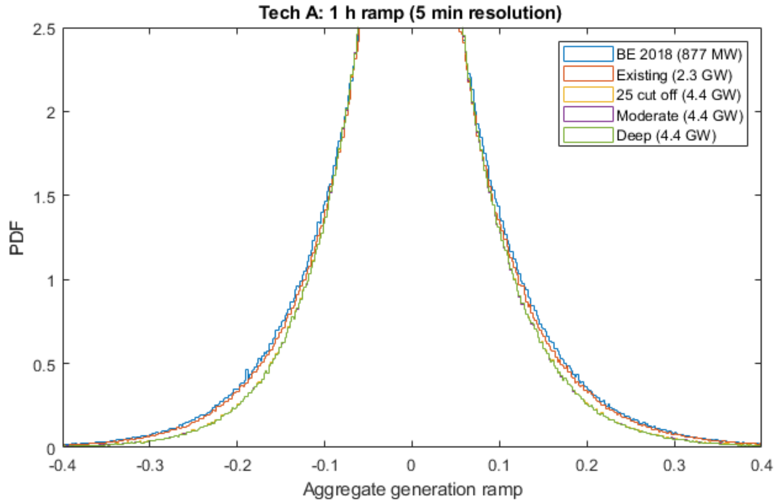


Figure 36. 1h ramp PDFs for example scenarios (standardized generation). The 4.4 GW scenarios with different storm shutdown types are almost fully on top of each other. "Existing" refers to the 2.3 GW of installations.

Table 20. 1 h ramp (5 min resolution) statistics (standardized generation).

			SD	Prct 0.01	Prct 0.1	Prct 99.9	Prct 99.99	Compared to BE 2018 SD	Compared to BE 2018 Prct 0.1	Compared to BE 2018 Prct 99.9
BE 2018 (877 MW)			0.092	-0.604	-0.425	0.463	0.732	100%	100%	100%
2.3 GW			0.088	-0.561	-0.395	0.434	0.629	96%	93%	94%
3.0 GW	**Tech A**	**25 m/s**	0.084	-0.522	-0.370	0.411	0.597	91%	87%	89%
		Moderate	0.083	-0.522	-0.370	0.409	0.596	91%	87%	88%
		Deep	0.083	-0.522	-0.367	0.407	0.592	90%	86%	88%
	Tech B	**25 m/s**	0.083	-0.531	-0.371	0.404	0.579	91%	87%	87%
		Moderate	0.083	-0.528	-0.372	0.404	0.580	90%	88%	87%
		Deep	0.083	-0.527	-0.371	0.401	0.578	90%	87%	87%
4.0 GW	**Tech A**	**25 m/s**	0.079	-0.520	-0.362	0.391	0.583	86%	85%	84%
		Moderate	0.078	-0.504	-0.350	0.382	0.572	85%	82%	83%
		Deep	0.078	-0.488	-0.342	0.374	0.543	85%	81%	81%
	Tech B	**25 m/s**	0.080	-0.516	-0.372	0.390	0.570	86%	88%	84%
		Moderate	0.079	-0.508	-0.360	0.379	0.563	85%	85%	82%
		Deep	0.078	-0.500	-0.352	0.371	0.549	85%	83%	80%
4.4 GW	**Tech A**	**25 m/s**	0.079	-0.541	-0.366	0.393	0.600	86%	86%	85%
		Moderate	0.078	-0.511	-0.351	0.383	0.577	85%	83%	83%
		Deep	0.078	-0.489	-0.343	0.375	0.544	85%	81%	81%
	Tech B	**25 m/s**	0.080	-0.537	-0.380	0.397	0.588	87%	89%	86%
		Moderate	0.079	-0.521	-0.363	0.382	0.576	86%	86%	83%
		Deep	0.078	-0.503	-0.354	0.374	0.553	85%	83%	81%
	Tech A/B	**25 m/s**	0.079	-0.537	-0.370	0.388	0.589	86%	87%	84%
		Moderate	0.078	-0.511	-0.357	0.377	0.570	85%	84%	81%
		Deep	0.078	-0.493	-0.350	0.368	0.547	85%	82%	80%

8.2 On the scenario with a mixture of Tech A and Tech B

The ramp rate distributions for the Tech A/B scenario for the BE 4.4 GW showed result in between the fully Tech A and fully Tech B scenarios. Thus, it was considered that analysing such mixed technology scenario does not provide any additional insight compared to analysing only the 100% Tech A and 100 % Tech B scenarios. The Tech A/B scenario is not included in the result presented later in the report.

8.3 Results in GW

This section describes the ramp rate results in GW. The simulated data is the same as in Section 8.1. The data are presented looking at the average number of days per year with at least one ramp event more extreme than a given value expressed in GW.

8.3.1 5 min ramps

Table 21 shows the average number of days per year with at least one ramp event more extreme than the given GW value for 5 min ramps. The differences between the scenarios are the same as discussed in Section 8.1.1, but here the scenarios with more installed GW of course show more extreme ramps.

Table 21. 5 min ramps: average number of days per year with at least one event more extreme than the limit.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)											0.2	0.4	0.1							
Existing (2.3 GW)										0.0	1.5	1.6	0.0							
3.0 GW	Tech A	25 m/s								1.6	7.6	7.7	1.4							
		Moderate								0.3	3.9	4.4	0.4							
		Deep								0.1	3.2	3.8	0.2							
	Tech B	25 m/s								1.9	9.1	8.1	1.5							
		Moderate								0.4	5.1	4.6	0.4							
		Deep								0.1	3.8	3.6	0.3							
4.0 GW	Tech A	25 m/s							0.1	3.9	13.6	13.0	3.4	0.1						
		Moderate								0.6	8.2	8.4	1.0	0.0						
		Deep								0.1	6.3	6.7	0.4							
	Tech B	25 m/s							0.1	4.2	17.2	16.0	4.0	0.1						
		Moderate								1.0	10.5	9.9	1.2	0.0						
		Deep								0.1	8.1	8.1	0.7							
4.4 GW	Tech A	25 m/s							0.4	5.9	19.1	19.1	5.1	0.4						
		Moderate							0.0	1.3	13.2	13.9	1.8	0.1						
		Deep								0.5	11.0	12.1	0.9	0.0						
	Tech B	25 m/s							0.3	7.5	24.3	23.6	6.3	0.3	0.0					
		Moderate								2.2	17.1	16.9	2.3	0.2						
		Deep								0.7	14.1	14.6	1.2	0.1						

“Existing” refers to the 2.3 GW of installations.

8.3.2 15 min ramps

Table 22 shows the average number of days per year with at least one ramp event more extreme than the given GW value for 15 min ramps (on 5 min resolution). The differences between the scenarios are the same as discussed in Section 8.1.2, but here the scenarios with more installed

GW of course show more extreme ramps. The tendency of the ramp PDF to be skewed slightly to the right is seen as higher number of events for example 2 GW up-ramps than 2 GW down-ramps (negative ramps). This is discussed further in Section 8.4 and Section 9.4.

Table 22. 15 min ramps: average number of days per year with at least one event more extreme than the limit.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)										0.4	1.9	2.4	0.4							
Existing (2.3 GW)										6.5	70.7	82.4	8.3	0.1						
3.0 GW	Tech A	25 m/s							0.1	17.4	126.3	140.5	21.1	0.4	0.1					
3.0 GW	Tech A	Moderate							0.1	13.8	123.2	137.9	17.9	0.3						
3.0 GW	Tech A	Deep							0.1	12.8	122.4	137.0	17.0	0.3						
3.0 GW	Tech B	25 m/s							0.1	18.2	129.5	138.9	21.7	0.4	0.0					
3.0 GW	Tech B	Moderate							0.1	14.6	125.2	135.1	18.0	0.4						
3.0 GW	Tech B	Deep							0.1	13.2	124.0	133.9	16.7	0.4	0.1					
4.0 GW	Tech A	25 m/s						0.6	2.8	35.2	191.3	198.9	38.6	2.7	0.5	0.1	0.0			
4.0 GW	Tech A	Moderate						0.0	0.5	30.8	188.1	195.5	34.5	1.3	0.3	0.1				
4.0 GW	Tech A	Deep							0.3	28.9	187.3	194.7	32.9	0.6	0.1	0.0				
4.0 GW	Tech B	25 m/s						0.5	3.3	40.6	199.6	203.5	41.9	3.4	0.6	0.2				
4.0 GW	Tech B	Moderate						0.0	0.8	34.6	194.6	199.1	36.5	1.5	0.3	0.1				
4.0 GW	Tech B	Deep							0.2	32.4	193.4	198.0	34.5	0.8	0.2	0.0				
4.4 GW	Tech A	25 m/s					0.3	1.2	4.4	53.6	227.1	232.9	59.3	4.5	1.2	0.3	0.1			
4.4 GW	Tech A	Moderate						0.2	1.3	48.9	223.9	229.6	55.0	2.3	0.5	0.1	0.0			
4.4 GW	Tech A	Deep							0.6	47.0	223.4	228.9	53.2	1.3	0.1	0.0				
4.4 GW	Tech B	25 m/s					0.2	1.5	5.5	64.1	234.9	239.6	64.0	5.7	1.3	0.4	0.1			
4.4 GW	Tech B	Moderate						0.3	2.1	58.1	230.2	235.2	58.0	2.7	0.5	0.2	0.0			
4.4 GW	Tech B	Deep						0.1	1.1	55.6	229.6	234.0	56.0	1.8	0.3	0.0	0.0			

"Existing" refers to the 2.3 GW of installations.

8.3.3 1 h ramps

Table 23 shows the average number of days per year with at least one ramp event more extreme than the given GW value for 1 h ramps (on 5 min resolution). The differences between the scenarios are the same as discussed in Section 8.1.3, but here the scenarios with more installed GW of course show more extreme ramps. The tendency of the ramp PDF to be skewed slightly to the right shows a higher number of events for example 2 GW up-ramps than 2 GW down-ramps. This is discussed further in Section 8.4 and Section 9.4.

Table 23. 1 h ramps: average number of days per year with at least one event more extreme than the limit.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)										4.2	57.2	65.3	7.5							
Existing (2.3 GW)							0.1	0.8	12.8	176.5	286.6	285.9	182.8	19.0	1.7	0.2				
3.0 GW	Tech A	25 m/s				0.1	0.4	3.3	33.4	229.8	308.0	305.5	233.9	45.3	6.6	0.9	0.2			
3.0 GW	Tech A	Moderate				0.1	0.4	3.3	32.8	227.7	306.9	304.1	232.0	44.8	6.5	1.0	0.2			
3.0 GW	Tech A	Deep				0.1	0.4	3.2	32.1	227.3	306.8	303.9	231.5	43.7	6.3	0.9	0.2			
3.0 GW	Tech B	25 m/s				0.1	0.5	3.5	34.1	233.3	310.7	308.4	236.1	44.1	5.8	0.9	0.2			
3.0 GW	Tech B	Moderate				0.1	0.5	3.4	33.8	230.2	308.5	306.3	233.4	43.7	5.8	0.9	0.2			
3.0 GW	Tech B	Deep				0.1	0.5	3.4	33.1	229.6	308.5	305.9	232.6	42.8	5.7	0.9	0.2			
4.0 GW	Tech A	25 m/s			0.1	0.4	2.9	13.9	77.5	267.6	322.3	319.5	268.9	91.5	20.1	5.1	1.2	0.3	0.1	
4.0 GW	Tech A	Moderate			0.1	0.4	2.2	11.8	74.7	265.2	320.9	317.9	266.6	88.9	18.4	4.2	1.2	0.3	0.1	
4.0 GW	Tech A	Deep			0.1	0.4	1.8	10.7	73.7	264.7	320.8	317.7	266.3	87.6	17.2	3.4	0.8	0.2	0.1	
4.0 GW	Tech B	25 m/s			0.1	0.5	3.2	17.1	83.0	272.3	325.4	323.9	273.6	90.9	20.4	4.5	1.0	0.2	0.1	
4.0 GW	Tech B	Moderate			0.1	0.5	2.7	14.7	78.9	268.5	322.9	321.7	270.0	87.1	17.6	4.0	1.0	0.3	0.1	
4.0 GW	Tech B	Deep			0.1	0.5	2.2	13.3	77.5	267.9	322.7	321.3	269.3	85.6	16.4	3.3	0.8	0.2	0.1	
4.4 GW	Tech A	25 m/s			0.2	1.6	6.3	21.9	105.4	282.8	328.1	325.7	282.5	118.1	30.4	8.6	3.0	0.7	0.2	0.1
4.4 GW	Tech A	Moderate			0.2	0.9	4.4	19.6	102.3	280.4	326.6	324.1	280.2	115.4	28.0	7.1	2.2	0.6	0.2	0.1
4.4 GW	Tech A	Deep			0.2	0.8	3.5	18.1	101.4	280.1	326.6	323.9	279.9	114.2	26.6	6.0	1.6	0.3	0.1	0.1
4.4 GW	Tech B	25 m/s			0.2	1.4	7.5	26.7	114.2	286.7	330.9	329.8	288.4	121.7	32.1	8.9	2.5	0.6	0.2	0.1
4.4 GW	Tech B	Moderate		0.0	0.2	1.0	5.1	23.6	109.8	283.0	328.5	327.6	284.7	117.6	28.7	6.9	2.2	0.7	0.2	0.1
4.4 GW	Tech B	Deep			0.2	1.0	4.1	22.0	108.3	282.4	328.5	327.4	284.1	116.1	27.0	5.7	1.6	0.5	0.2	0.1

"Existing" refers to the 2.3 GW of installations.

8.4 Ramps when daily max wind speed is low

The previous section has shown expected ramp event likelihoods when considering all the simulated days. This section shows the likelihoods when considering only days when the maximum daily wind speeds (fleet-level mean, weighted by installed capacity) is below 20 m/s. Such days cover approximately 92 % of all the simulated days.

Looking at the 1 h ramp events on the days with maximum wind speed below 20 m/s in Table 24 and comparing to Table 23, it can be seen that the most extreme up-ramps are unlikely to happen on days without high wind speed. However, a single up-ramp event higher than 4 GW in the 4.4. GW scenarios occurs during a day without maximum wind speed above 20 m/s. This event is plotted for the BE 4.4 GW Tech A scenarios in Figure 37; the same date caused also the extreme up-ramp for the Tech B scenarios. This shows that extreme ramps can happen also without a storm; however, such extreme event happened only once during the 37 years of simulations (5 min resolution). The single event visualised in Figure 37 is the cause for having an event with higher than 3.5 and 4 GW up-ramp in Table 24. Even though this extreme event is an up-ramp event, it is possible that also an extreme down-ramp event can happen in the future. Up- and down-ramp probabilities are compared for storm days in Section 9.3.

Next to these most extreme events, the results for 4.4GW installed capacity in Table 24 show that ramps of more than 2 GW in 1 hour are to be expected approximately 3 days a year for down-ramps and 4 days a year for up-ramps. And ramps > 2.5 GW less than 1 day a year for down-ramps and around 1 day a year for up-ramps and, on average. These results are for days with max wind speed below 20 m/s; results for storm-days are presented in Section 9.3.

The 5 min and 15 min ramp event tables for days with maximum wind speed below 20 m/s are shown in Appendix E: 5 min ramp statistics for days with maximum wind speed below 20 m/s and Appendix F: 15 min ramp statistics for days with maximum wind speed below 20 m/s. The numbers show that the highest 5 and 15 min ramps do not tend to occur on days without a high wind speed (> 20 m/s).

Table 24. 1 h ramps: average number of days per year with at least one event when the daily max fleet-level wind speed is below 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	**3.5**	**3.0**	**2.5**	**2.0**	**1.5**	**1.0**	**0.5**	**0.3**	**0.3**	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**
BE 2018 (877 MW)										2.8	49.9	56.1	4.6							
Existing (2.3 GW)							0.1	0.5	11.2	163.9	266.4	265.3	168.7	16.1	1.1	0.1				
3.0 GW	**Tech A**	**25 m/s**				0.0	0.3	2.6	28.4	212.1	285.2	282.2	215.1	38.4	4.8	0.5	0.1			
		Moderate				0.0	0.3	2.6	28.4	212.1	285.2	282.2	215.0	38.4	4.8	0.5	0.1			
		Deep				0.0	0.3	2.6	28.4	212.1	285.2	282.2	215.0	38.4	4.8	0.5	0.1			
	Tech B	**25 m/s**				0.1	0.3	2.7	29.3	214.2	286.5	283.6	215.8	37.3	4.3	0.5	0.1			
		Moderate				0.1	0.3	2.7	29.3	214.1	286.5	283.6	215.6	37.3	4.3	0.5	0.1			
		Deep				0.1	0.3	2.7	29.3	214.1	286.5	283.6	215.6	37.3	4.3	0.5	0.1			
4.0 GW	**Tech A**	**25 m/s**			0.1	0.3	1.5	9.1	67.2	248.2	299.0	295.9	248.5	79.4	14.1	2.6	0.5	0.1	0.0	
		Moderate			0.1	0.3	1.5	9.1	67.2	248.1	299.0	295.9	248.4	79.4	14.1	2.6	0.5	0.1	0.0	
		Deep			0.1	0.3	1.5	9.1	67.2	248.1	299.0	295.9	248.4	79.4	14.1	2.6	0.5	0.1	0.0	
	Tech B	**25 m/s**			0.1	0.4	1.9	11.4	70.9	251.0	299.9	298.0	251.6	77.5	13.8	2.3	0.3	0.0	0.0	
		Moderate			0.1	0.4	1.9	11.4	70.9	250.9	299.9	297.9	251.5	77.4	13.7	2.2	0.3	0.0	0.0	
		Deep			0.1	0.4	1.9	11.4	70.9	250.9	299.9	297.9	251.5	77.4	13.7	2.2	0.3	0.0	0.0	
4.4 GW	**Tech A**	**25 m/s**			0.1	0.6	2.9	15.8	93.3	262.2	304.1	301.5	261.1	104.1	22.6	4.6	1.1	0.1	0.0	0.0
		Moderate			0.1	0.6	2.9	15.8	93.2	262.2	304.1	301.5	261.1	104.1	22.5	4.6	1.1	0.1	0.0	0.0
		Deep			0.1	0.6	2.9	15.8	93.2	262.2	304.1	301.5	261.1	104.1	22.5	4.6	1.1	0.1	0.0	0.0
	Tech B	**25 m/s**			0.1	0.7	3.4	19.1	100.2	264.4	304.5	303.1	265.2	106.3	23.4	4.2	0.8	0.2	0.0	0.0
		Moderate			0.1	0.7	3.4	19.1	100.1	264.3	304.5	303.0	265.1	106.2	23.2	4.2	0.8	0.2	0.0	0.0
		Deep			0.1	0.7	3.4	19.1	100.1	264.3	304.5	303.0	265.1	106.2	23.2	4.2	0.8	0.2	0.0	0.0

Days with maximum fleet-level wind speed below 20 m/s cover approximately 92 % of the simulated days (small differences between the scenarios). "Existing" refers to the 2.3 GW of installations.

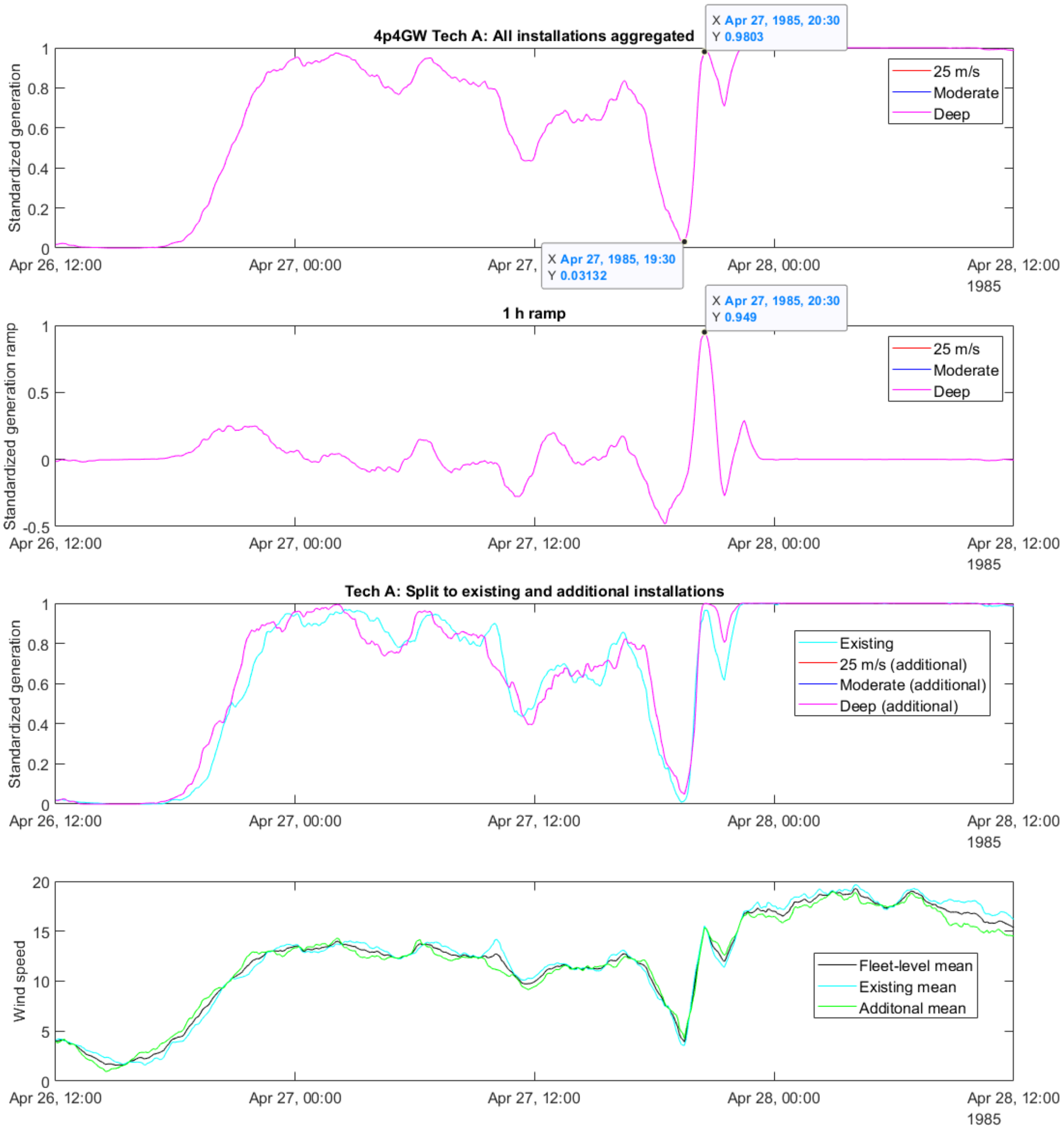


Figure 37. The most extreme up-ramp event for the BE 4.4 GW Tech A scenario when considering days with max wind speed below 20 m/s. As wind speeds are < 20 m/s, all storm shutdown types show the same generation time series. "Existing" refers to the 2.3 GW of installations and "additional" to the 2.1 GW of additional installation to reach 4.4. GW.

8.5 Conclusions on ramps

Considering standardized generation, ramps are expected to be reduced towards the 4.4 GW of installations. This is caused by geographical smoothening. 5 min ramps are reduced more than 1 h ramps. However, when expressed in GW, ramps are expected to increase significantly in the future. In the 4.4 GW scenarios, ramps of more than 2 GW in 1 hour are expected to occur multiple times in a year. 1 hour down-ramp larger than 2.5 GW is expected on approximately one day in a year, and 1 hour up-ramp of more than 2.5 GW approximately on 2 or 3 days a year. Extreme up-ramps are more likely than similar size down-ramps (this is discussed more in Section 9.4).

The results show that the highest 5 and 15 min ramps do not tend to occur on days without a high wind speed (fleet-level mean wind speed > 20 m/s). However, even for non-storm days, an up-ramp larger than 4 GW within 1 hour (5 min resolution) was seen once in the simulation for the 4.4 GW scenarios. This shows that the most extreme ramps are possible also on non-storm days, but they are unlikely. Even though similar size down-ramp was not seen in the simulations, it cannot be ruled out that such down-ramp events could not happen in the future. However, generally, extreme ramps tend to occur more on storm days, as presented in section 9.

As described in Section 6.5, unavailability is not modelled (100 % availability is assumed). It is important to note that the likelihoods of the most extreme ramp events may be slightly underestimated, based on the comparison between measured and simulated data in Section 6.

9. Statistical analysis of storm events

This chapter presents statistics of storm events in the simulated 37 years of data. Both the likelihoods of fleet-wide shutdowns and ramping during high wind speed days are reported. All results are given based on 5 min resolution data.

Note that when comparing the 2.3 GW part (existing + planned OWPPs) and the 2.1 GW of additional installations to reach the 4.4 GW of offshore wind, the 2.3 GW part is referred to as "existing" and 2.1 GW as "additional" in the figures.

9.1 Simulated 37 years of wind speeds

Simulated fleet-level wind speeds for the BE 4.4 GW Tech A scenario can be seen in Figure 38. The highest fleet-level wind speeds reach approximately 35 m/s (5 min resolution); highest plant-level wind speeds are even higher. It can be observed that high wind speeds occur throughout the 37 years; however, the latest few years up to 2018 do not show very high wind speed peaks, meaning that the most extreme weather conditions have not yet been experienced by the offshore wind parks. Tech B shows slightly higher fleet-level wind speeds due to additional installations having higher hub heights.

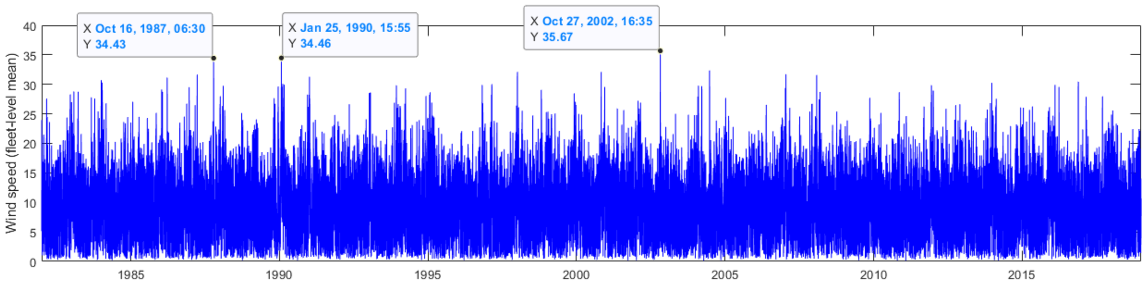


Figure 38. Effective fleet-level wind speeds (weighted by OWPP installed capacity) in the BE 4.4 GW Tech A scenario (5 min resolution). Time series are until the end of 2018; some of the highest peaks are marked.

9.2 Generation during storms

Example time series around the 1990 extreme high wind speed event (as seen in Figure 38) can be seen in Figure 39. With such high wind speeds, the entire fleet (4.4 GW) is in shutdown for some hours with all the scenarios considered. In this specific example, the Moderate and Deep types show smoother ramping than the 25 direct cut-off; however, on the aggregate 4.4 GW level (top subplot), they all reach zero generation at the same time. The 2.3 GW of installations (existing) show smooth shutdown behaviour, because some OWPPs have a higher than 25 m/s cut-off limit and many OWPPs have the Deep shutdown behaviour also in the 2.3 GW of installations (middle subplot). The 2.3 GW (existing) shut down later than the Deep additional 2.1 GW of installations because wind speeds in the 2.3 GW installation locations increase later and up to a lower maximum level than in the additional 2.1 GW locations (bottom subplot).

Figure 40 shows that even with the Deep shutdown type, the 4.4 GW Tech A scenario is expected to sometimes experience a full shut-down. Figure 41 shows that the storm shut down type does not have a significant impact on the number of occurrences where the entire fleet experiences a total shut-down; although the Deep types shows slightly less shut-down hours. These observations are in line with the case plotted in Figure 39. However, Figure 39 also suggest that there are differences in ramping during storm events for the different shutdown types; this is investigated in the following sections. And the shutdown type impacts the expected number of shut-down hours per year for the additional (2.1 GW) part of the installations: see Appendix G: Number of hours per year in full shut-down (additional 2.1 GW only).

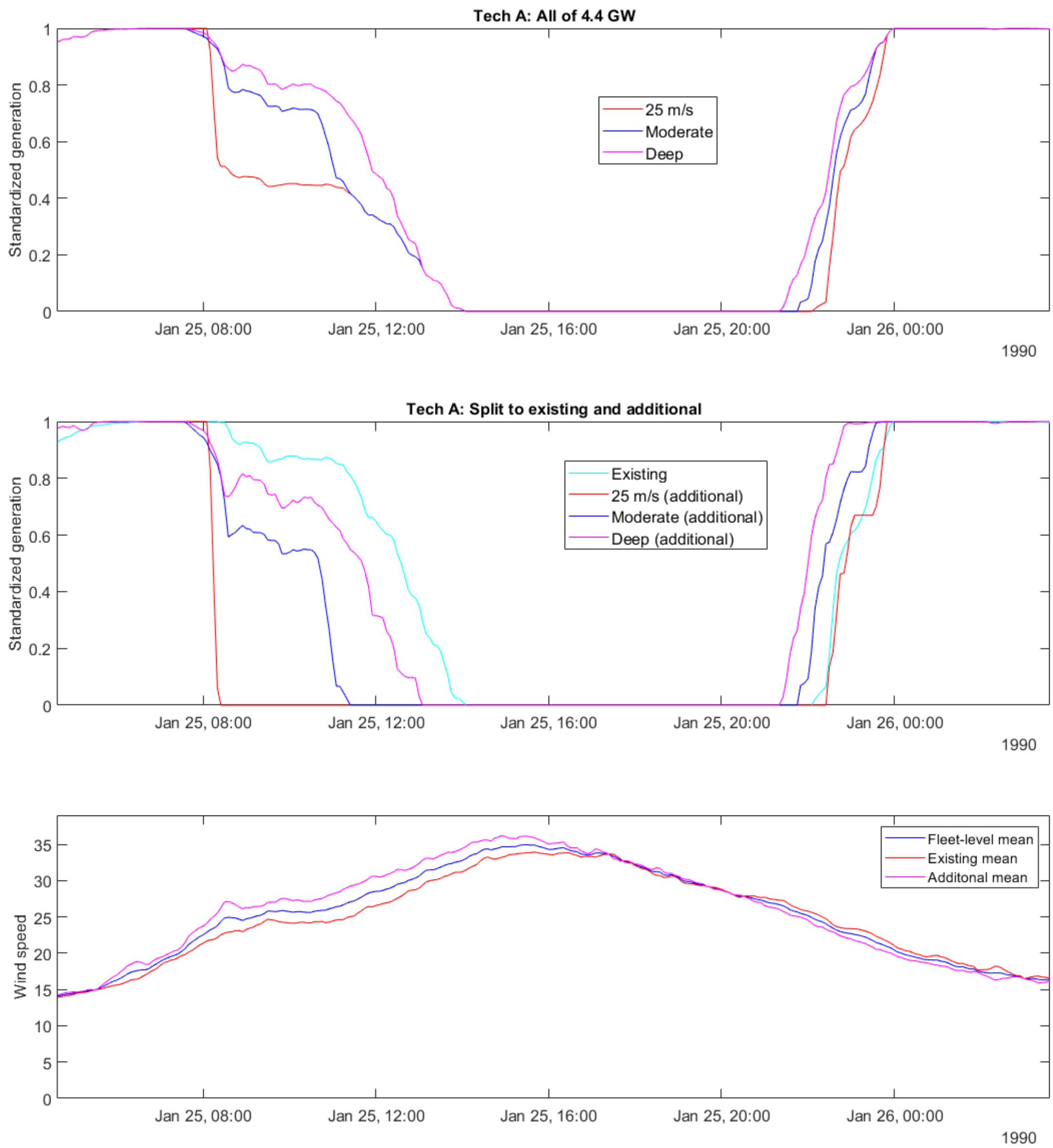


Figure 39. Example extreme storm case for the BE 4.4 GW Tech A scenario: all storm shutdown types plotted. "Existing" refers to the 2.3 GW of installations and "additional" to the 2.1 GW of additional installation to reach 4.4 GW.

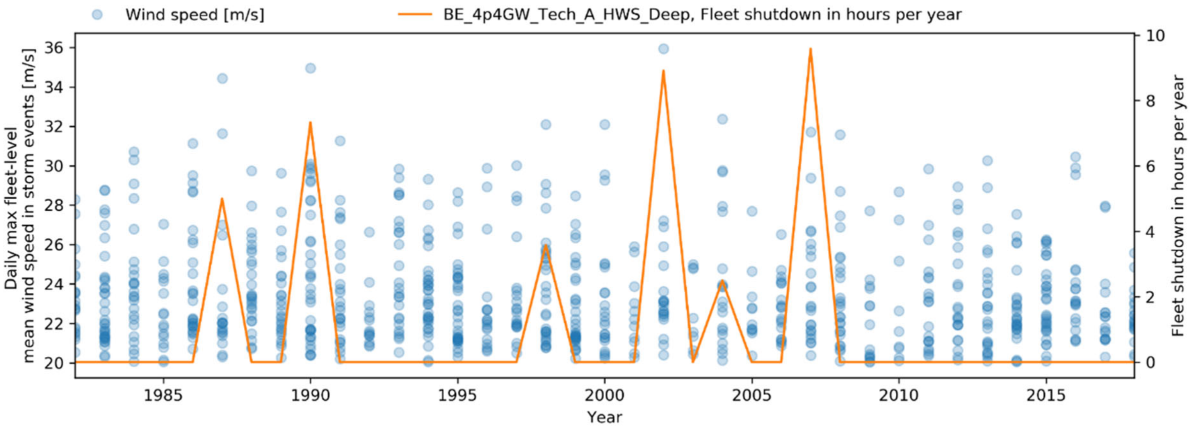


Figure 40. Number of hours when the entire fleet is in shutdown (aggregate generation zero) per year for the BE 4.4 GW Tech A Deep storm shutdown scenario.

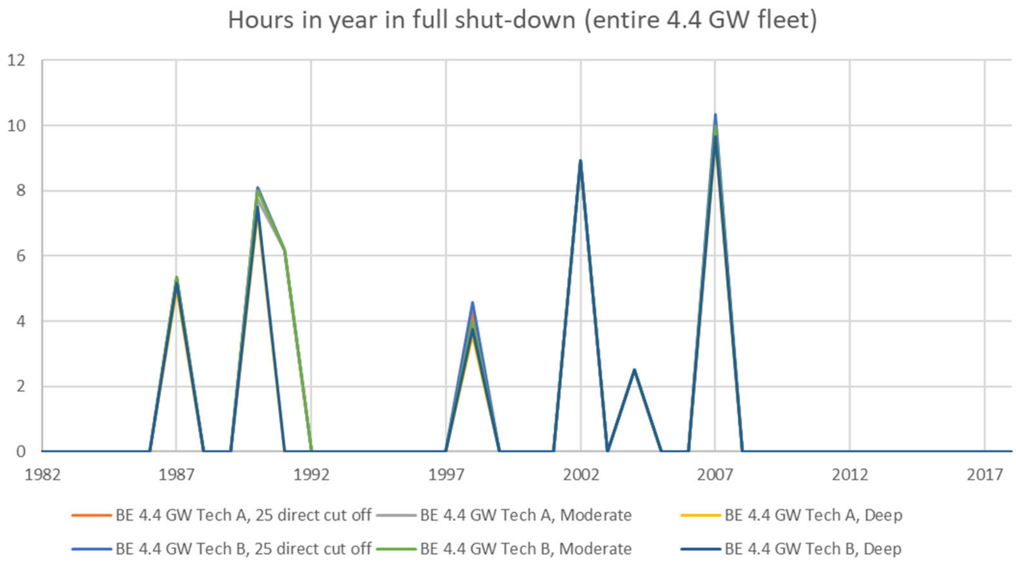


Figure 41. Number of hours when the entire fleet is in shut-down (aggregate generation zero) per year for the 4.4 GW scenarios. Full shut-down occurs in 6 or 7 of the 37 simulated years.

9.3 Ramps during high wind speed days

9.3.1 5 min ramps

Table 25 shows the average number of days per year with at least one ramp event more extreme than the given GW limit for 5 min ramps for those days when the daily max wind speed is above 20 m/s**.** Comparing to Table 21 (which considers all simulated days) and Appendix E: 5 min ramp statistics for days with maximum wind speed below 20 m/s, it can be seen that most days with extreme 5 min ramps occur on high wind days. Table 25 shows that the Deep type shows significantly reduced likelihoods for extreme ramps compared to direct 25 cut-off.

Table 25. 5 min ramps: average number of days per year with at least one event more extreme than the limit for days with max fleet-level wind speed above 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)											0.2	0.4	0.1							
Existing (2.3 GW)											0.6	0.7	0.0							
3.0 GW	Tech A	25 m/s								1.2	5.0	4.9	0.9							
		Moderate								0.2	1.6	1.9	0.3							
		Deep								0.1	1.0	1.4	0.1							
	Tech B	25 m/s								1.4	6.0	5.6	1.1							
		Moderate								0.3	2.4	2.5	0.4							
		Deep								0.1	1.1	1.5	0.2							
4.0 GW	Tech A	25 m/s							0.1	3.3	7.9	7.3	2.8	0.1						
		Moderate								0.6	3.2	3.5	0.8	0.0						
		Deep								0.1	1.5	1.9	0.3							
	Tech B	25 m/s							0.1	3.5	10.0	9.1	3.3	0.1						
		Moderate								0.9	4.2	3.9	0.9	0.0						
		Deep								0.1	1.8	2.2	0.5							
4.4 GW	Tech A	25 m/s							0.4	4.9	9.2	9.0	4.1	0.4						
		Moderate							0.0	1.1	4.1	4.5	1.4	0.1						
		Deep								0.2	2.0	2.7	0.5	0.0						
	Tech B	25 m/s							0.2	6.2	11.8	11.2	5.1	0.3	0.0					
		Moderate								1.7	5.4	5.4	1.8	0.2						
		Deep								0.2	2.5	3.2	0.8	0.1						

Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

9.3.2 15 min ramps

Table 26 shows the average number of days per year with at least one ramp event more extreme than the given GW limit for 15 min ramps for those days when the daily max wind speed is above 20 m/s**.** Comparing to Table 22 (which considers all simulated days) and Appendix F: 15 min ramp statistics for days with maximum wind speed below 20 m/s, it can be seen that most days with extreme 15 min ramps occur on high wind days. Table 26 shows that the Deep type shows significantly reduced likelihoods for extreme ramps compared to direct 25 cut-off, especially on down-ramps. The number of extreme up-ramp events is also reduced, but not as much; this is discussed more in Section 9.4.

Table 26. 15 min ramps: average number of days per year with at least one event more extreme than the limit for days with max fleet-level wind speed above 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)										0.4	1.4	2.1	0.4							
Existing (2.3 GW)										0.8	7.2	9.4	1.8	0.1						
3.0 GW	Tech A	25 m/s							0.1	6.1	14.4	16.3	7.1	0.4	0.1					
		Moderate							0.1	2.9	11.5	13.8	4.2	0.3						
		Deep							0.1	1.9	10.7	12.9	3.3	0.2						
	Tech B	25 m/s							0.1	6.7	16.2	17.5	8.1	0.4	0.0					
		Moderate							0.1	3.5	12.2	13.9	4.8	0.4						
		Deep							0.1	2.1	11.0	12.7	3.6	0.4	0.1					
4.0 GW	Tech A	25 m/s						0.6	2.6	9.4	17.8	19.1	10.1	2.6	0.5	0.1	0.0			
		Moderate						0.0	0.4	5.5	14.6	15.8	6.5	1.2	0.2	0.1				
		Deep							0.2	3.7	13.9	15.0	4.9	0.5	0.1	0.0				
	Tech B	25 m/s						0.5	3.1	11.7	19.6	20.4	11.8	3.3	0.5	0.2				
		Moderate						0.0	0.7	6.2	14.9	16.3	7.0	1.3	0.3	0.1				
		Deep							0.1	4.0	13.7	15.2	5.1	0.7	0.2	0.0				
4.4 GW	Tech A	25 m/s					0.3	1.2	3.9	11.3	19.4	20.4	12.2	3.9	1.1	0.3	0.1			
		Moderate						0.2	0.9	7.0	16.3	17.2	8.5	1.7	0.5	0.1	0.0			
		Deep							0.2	5.2	15.8	16.5	6.8	0.8	0.1	0.0				
	Tech B	25 m/s					0.2	1.5	4.6	13.6	21.2	21.6	14.1	4.8	1.3	0.4	0.1			
		Moderate						0.3	1.3	8.1	16.6	17.4	8.8	1.9	0.5	0.2	0.0			
		Deep						0.0	0.3	5.7	16.0	16.2	6.8	1.0	0.3	0.0	0.0			

Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

9.3.3 1 h ramps

Table 27 shows the average number of days per year with at least one ramp event more extreme than the given GW limit for 1 h ramps for those days when the daily max wind speed is above 20 m/s**.** Comparing to Table 23 (which considers all simulated days) and Table 24 (days when max wind speed is below 20 m/s), it can be seen that proportionally more days with extreme 1 h ramps occur on high wind days (considering that those days are only about 8 % of all simulated days); but this difference is not as clear as with the 5 and 15 min ramps.

Table 27 shows that the Deep type has reduced likelihoods for negative ramps over 2 GW compared to 25 direct cut-off for the 4.0 and 4.4 GW scenarios, but even the Deep type can experience very high negative ramps (3 GW or more), and the Moderate type for BE 4.4 GW Tech B actually shows higher extreme down-ramp than the 25 direct cut-off scenario; this case is visualised in Figure 42. More discussion is provided in Section 9.5. The number of extreme up-ramp events is not significantly reduced when comparing the 25 direct cut-off to the Deep type; this is discussed more in Section 9.4.

Table 27. 1 h ramps: average number of days per year with at least one event more extreme than the limit for days with max fleet-level wind speed above 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)										1.4	7.3	9.2	2.9							
Existing (2.3 GW)							0.0	0.3	1.7	12.6	20.1	20.5	14.0	2.8	0.6	0.1				
3.0 GW	Tech A	25 m/s				0.0	0.1	0.6	5.0	17.8	22.8	23.3	18.8	6.9	1.8	0.5	0.2			
		Moderate				0.1	0.1	0.6	4.3	15.7	21.7	21.9	17.0	6.4	1.7	0.5	0.2			
		Deep				0.1	0.1	0.5	3.6	15.3	21.6	21.8	16.5	5.3	1.5	0.4	0.1			
	Tech B	25 m/s				0.0	0.1	0.8	4.8	19.1	24.2	24.8	20.3	6.8	1.5	0.4	0.1			
		Moderate				0.0	0.1	0.6	4.5	16.1	22.1	22.7	17.7	6.4	1.5	0.5	0.1			
		Deep				0.1	0.1	0.6	3.8	15.5	22.0	22.4	16.9	5.5	1.4	0.4	0.2			
4.0 GW	Tech A	25 m/s				0.1	1.5	4.8	10.3	19.4	23.4	23.6	20.5	12.2	6.0	2.4	0.7	0.2	0.1	
		Moderate			0.0	0.1	0.8	2.7	7.6	17.1	21.9	22.1	18.1	9.6	4.2	1.6	0.7	0.2	0.1	
		Deep			0.0	0.1	0.3	1.6	6.6	16.6	21.8	21.8	17.9	8.2	3.1	0.8	0.3	0.1	0.1	
	Tech B	25 m/s				0.1	1.4	5.8	12.1	21.3	25.4	25.9	22.0	13.4	6.6	2.2	0.7	0.2	0.1	
		Moderate			0.0	0.1	0.8	3.4	8.0	17.5	23.0	23.8	18.5	9.7	4.0	1.8	0.6	0.3	0.1	
		Deep			0.0	0.1	0.3	1.9	6.6	16.9	22.8	23.4	17.8	8.2	2.7	1.1	0.5	0.2	0.1	
4.4 GW	Tech A	25 m/s			0.1	1.0	3.4	6.1	12.1	20.7	23.9	24.2	21.5	14.1	7.8	4.0	1.9	0.5	0.2	0.1
		Moderate			0.1	0.3	1.5	3.8	9.1	18.2	22.5	22.7	19.2	11.4	5.5	2.5	1.1	0.5	0.2	0.1
		Deep			0.0	0.2	0.6	2.3	8.2	17.9	22.4	22.5	18.8	10.1	4.1	1.4	0.5	0.2	0.1	0.1
	Tech B	25 m/s			0.1	0.6	4.0	7.6	14.0	22.3	26.4	26.6	23.2	15.4	8.8	4.6	1.6	0.5	0.2	0.1
		Moderate		0.0	0.1	0.3	1.7	4.5	9.6	18.7	24.0	24.5	19.7	11.4	5.5	2.7	1.4	0.5	0.2	0.1
		Deep			0.1	0.2	0.7	2.9	8.2	18.1	23.9	24.4	19.1	9.9	3.9	1.5	0.8	0.4	0.2	0.1

Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

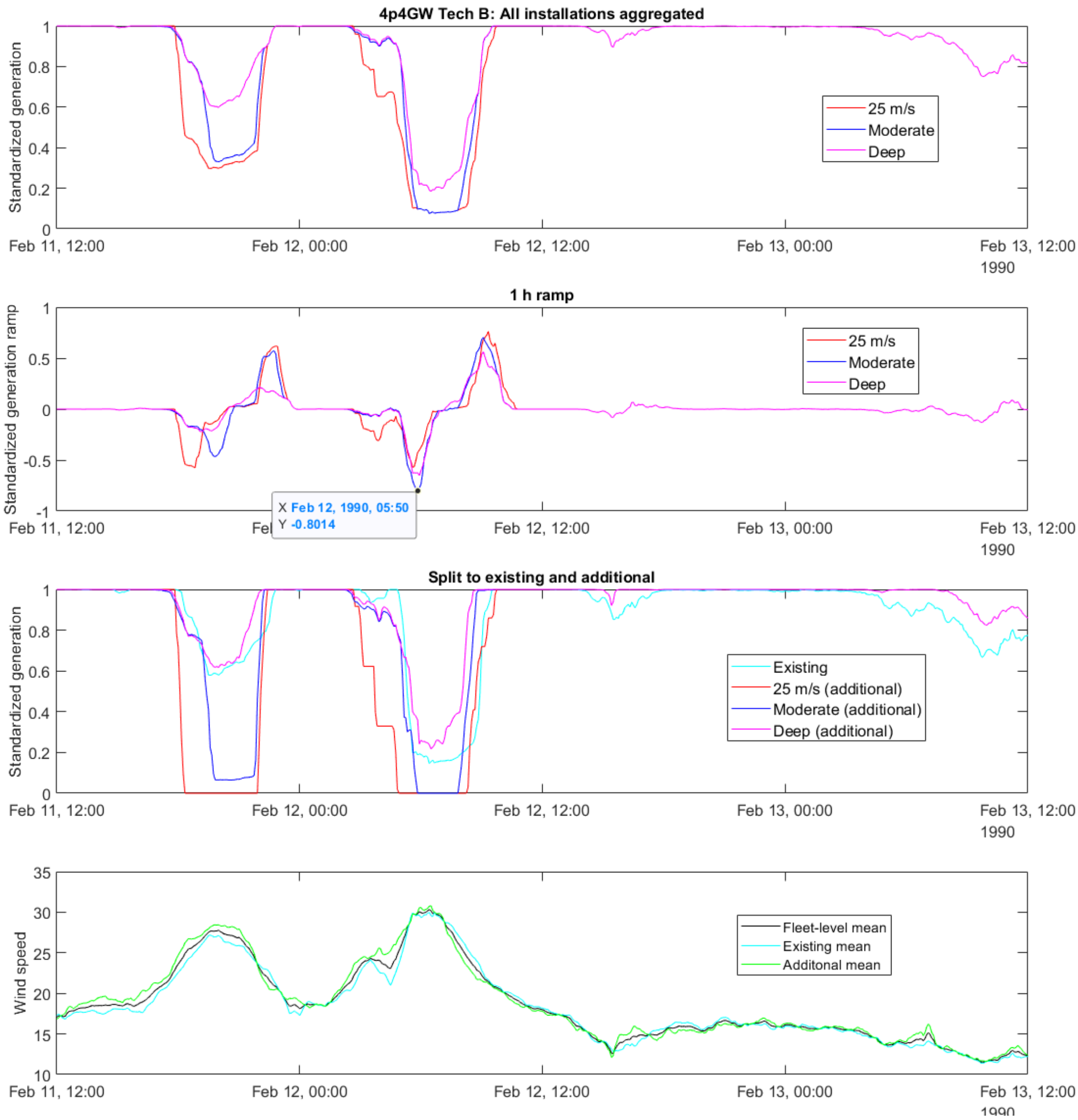


Figure 42. The storm event case for BE 4.4 GW Tech B with more than 3.5 GW 1h down-ramp for the Moderate storm shutdown type. “Existing” refers to the 2.3 GW of installations and “additional” to the 2.1 GW of additional installations to reach 4.4 GW.

9.4 On the large up-ramps

From Table 25, Table 26 and Table 27, it can be seen that up-ramps are more likely than down-ramps of the same magnitude for high wind speed days. For Moderate and Deep types, this is impacted by the storm shutdown types only affecting the shutdown and not the restart operation during storm (this can be seen in Figure 10). An example of this is shown in Figure 43: all the shutdown types experience a very fast 15 min up-ramp. In this case, the Deep and Moderate types show even larger 15 min up-ramp than the 25 direct cut-off type.

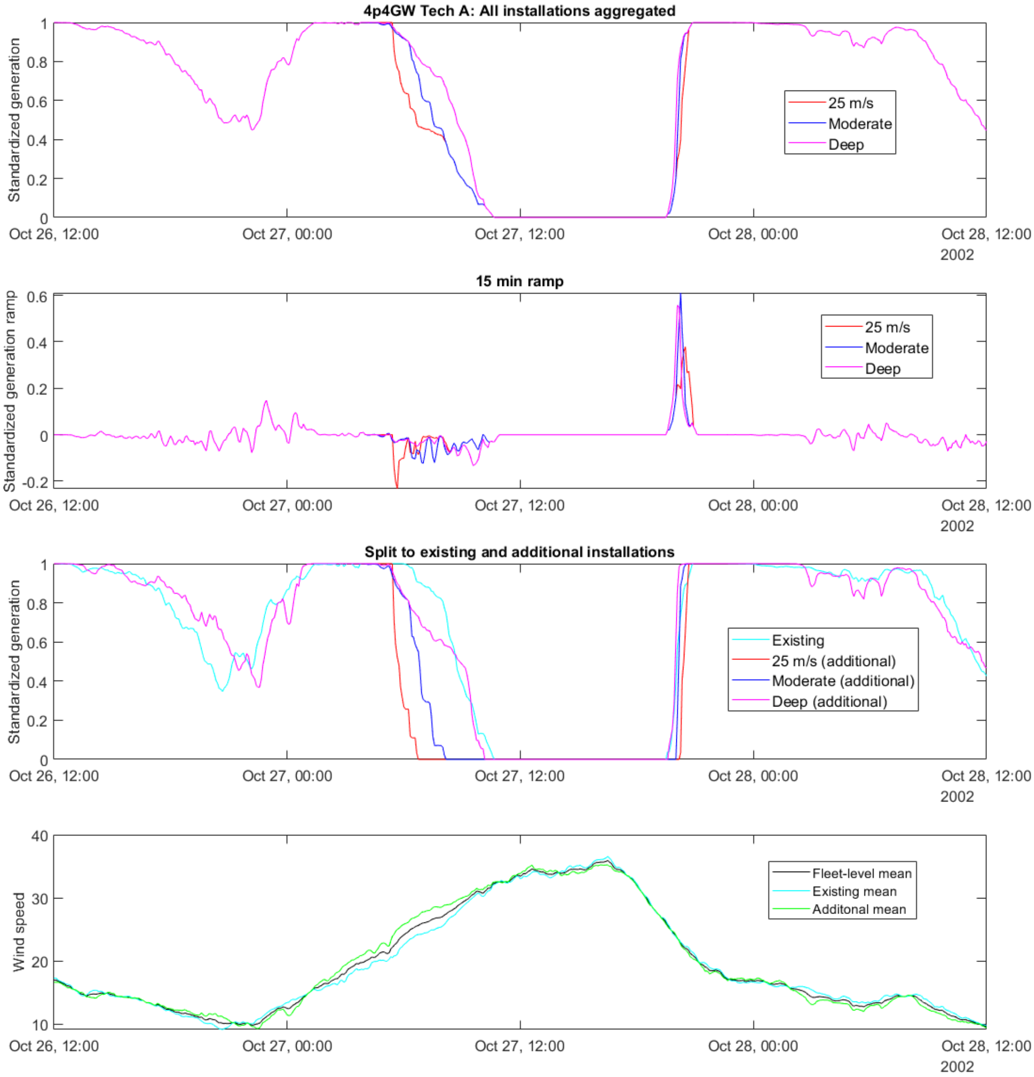


Figure 43. Example storm case for BE 4.4 GW Tech A, where the restart after the storm causes an extreme 15 min up-ramp, especially for the Moderate and the Deep types. "Existing" refers to the 2.3 GW of installations and "additional" to the 2.1 GW of additional installations to reach 4.4 GW.

9.5 On the down-ramps on fleet-level

As was shown in Table 27, the likelihoods of extreme 1 h down-ramp (more than 2.5 GW) during high wind speed day are not very different for the different storm shut-down types, although the 2 GW-level down-ramp likelihoods are reduced compared to moderate and deep types (considering the 4.4 GW scenarios). A very clear reason for this was not found; however, it seems that during the extreme ramps cases there can be an unfortunate correlation of ramps between the 2.3 GW and additional installations. An example of this can be seen in Figure 44: when looking only at the additional installations (3rd subplot), the Deep type shows smoother storm operation compared to the 25 direct cut-off. However, it can be seen in the same subplot that the storm shut-down of the additional Deep type correlates with the shut-down operation of the 2.3 GW of installations. As a result, on the aggregate 4.4 GW-level, the 1 h ramp of the Deep scenario is more severe than the 25 direct cut-off scenario. This unfortunate lag (additional installations ramping down first and the 2.3 GW later) is related to the wind speed in the additional installations increasing before the wind speeds in the 2.3 GW locations increase (bottom subplot of Figure 44).

Similar phenomena as in Figure 44 can be seen also in Figure 42; in Figure 42, the Moderate type shows the most severe 1 h down-ramp.

The above-mentioned phenomena may relate to storms usually coming from the west (see Figure 7 on the geographical locations of the installations); this would explain the wind speeds increasing first in the additional 2.1 GW (west) installations and later in the 2.3 GW installations (east). A geographical visualisation in Figure 45 of the time series in Figure 44 seems to show that at least in this case the storm moved from west to east. However, the reasons behind these observations have not been fully assessed and would need a deeper analysis before being confirmed. The phenomena was seen on 1 h ramps, but not so significantly on the 5 min or 15 min ramps, which might be explained by the distance between the 2.3 GW and the additional 2.1 GW installation clusters.

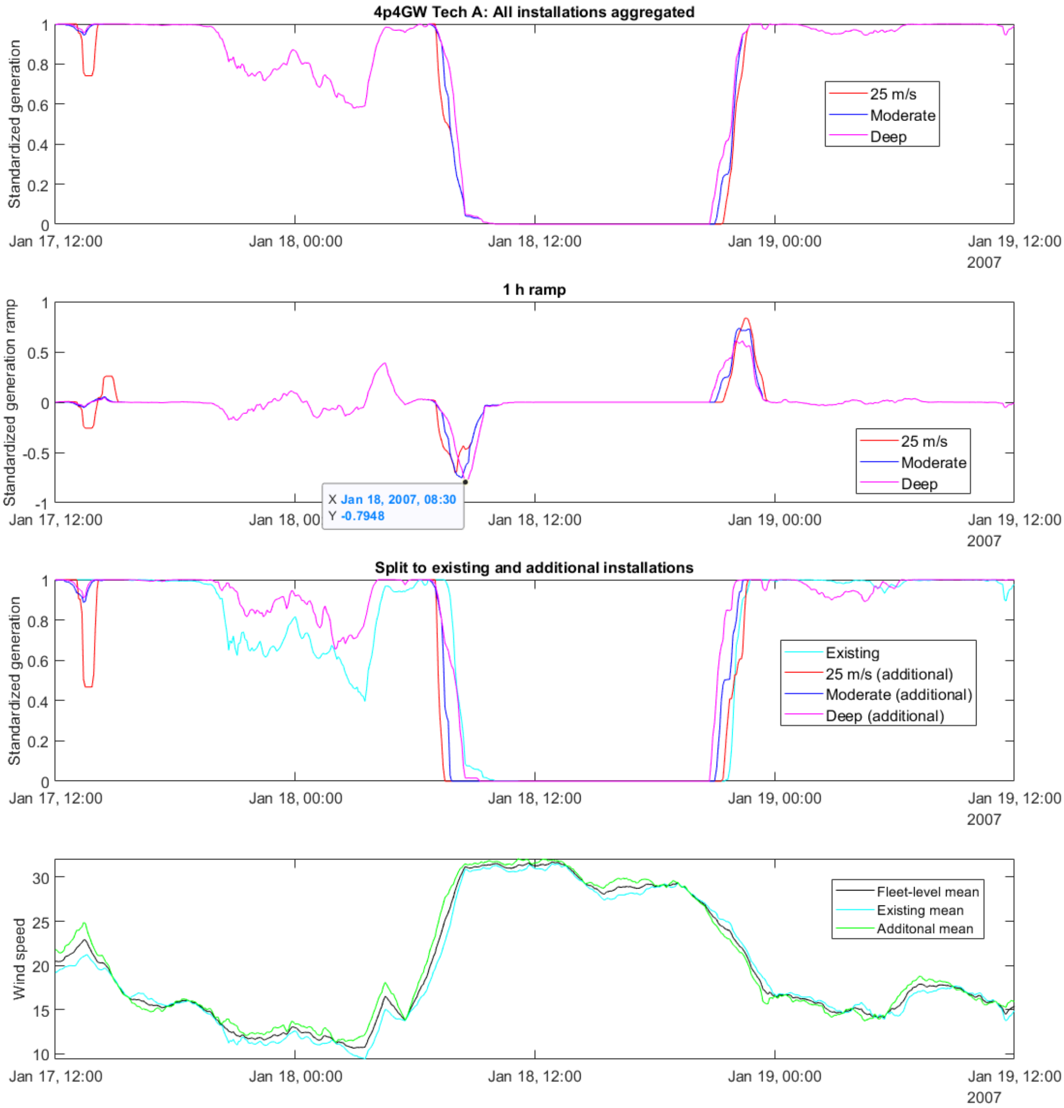


Figure 44. Example storm case for BE 4.4 GW Tech A, where largest 1 h down-ramp for the Deep type is more severe than for the 25 direct cut-off. "Existing" refers to the 2.3 GW of installations and "additional" to the 2.1 GW of additional installations to reach 4.4 GW.

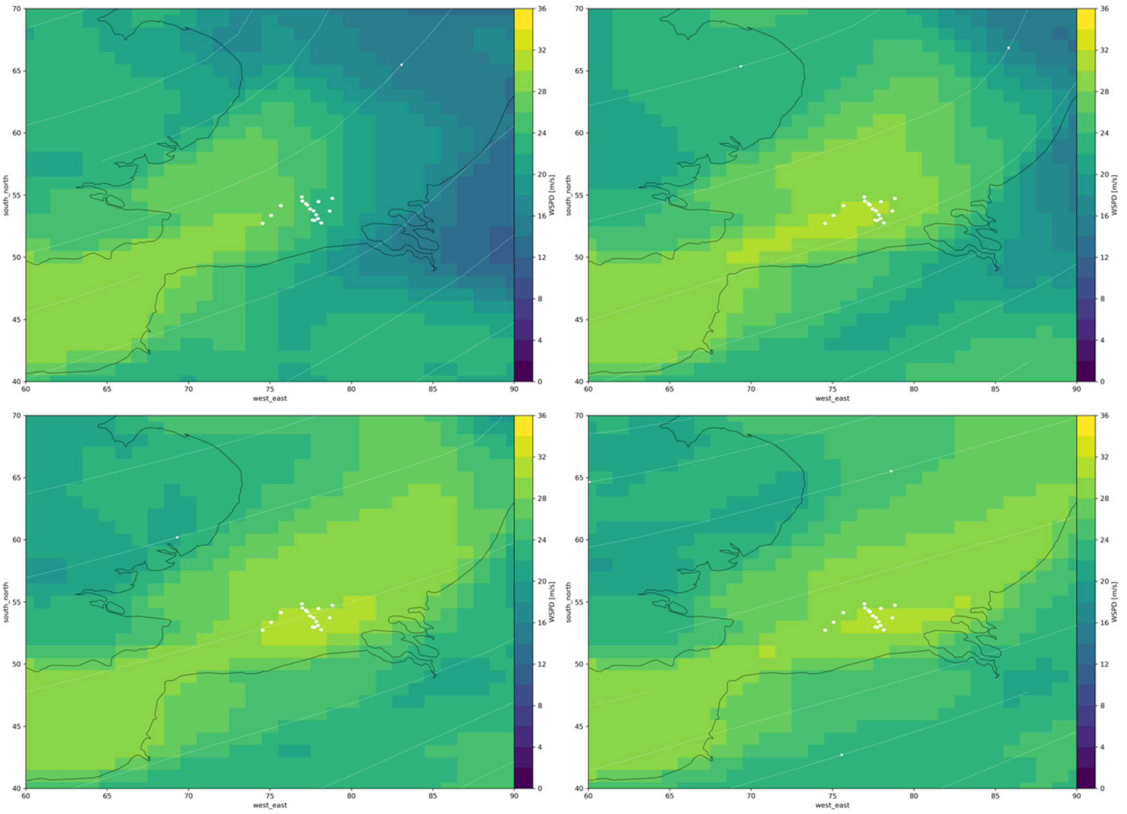


Figure 45. Wind speed maps (WRF directly) and wind direction streamlines for the example storm case for BE 4.4 GW Tech A, where largest 1 h down-ramp for the Deep type is more severe than for the 25 direct cut-off. Top left: 18 January 2007 07:00 AM. Top right: 18 January 2007 8:00 AM. Bottom left: 18 January 2007 9:00 AM. Bottom right: 18 January 2007 10:00 AM.

9.6 Conclusions on storm events

It is possible to lose the full 4.4 GW of installed capacity in all studied cases due to an extreme storm event. The number of years where this occurs is 6 or 7 out of the simulated 37 years for the 4.4 GW scenarios, depending on the technology scenario.

Storm shutdown type impacts the most extreme fast ramps by slowing down the down-ramps during storms. 5 and 15 min extreme down ramps are reduced significantly when comparing the Deep to the 25 direct cut-off type. The following numbers are for the 4.4 GW scenarios. For 15 min ramps, a larger than 2 GW down-ramp was seen in the simulations a few times over the 37 years for the 25 direct cut-off types, but such event was not seen for scenarios with the Deep or Moderate storm type. The Deep type shows a reduction of down-ramps compared to the Moderate type: 15 min down-ramps of > 1 GW and > 1.5 GW are approximately half as likely for the Deep than for the Moderate type. A 5 min down-ramp of more than 1 GW is expected less than once a year for the 25 direct cut-off type, but such event is not seen for scenarios with the Deep type, and only once in the simulated 37 years for the Moderate type. A 5 min down-ramp of more than 0.5 GW is expected to occur on multiple days a year for the 25 direct cut-off type, on 1 or 2 days for the Moderate type and less than one day a year for the Deep type.

For 1 hour ramps in the 4.4 GW scenarios on high wind speed days, a down-ramp event of more than 2 GW is expected to happen on a few days over a year with the 25 direct cut-off type. For similar scenarios with the Deep storm shutdown type, such event is expected on less than one day a year. However, on the fleet-level (4 or 4.4 GW), the most severe 1 hour down-ramps are similar for all shutdown types. A very clear reason was not found, but it may be because of storms coming from the west and causing shut-down first for the additional 2.1 GW installations and after some time for the 2.3 GW installations, which can cause an unfortunate aggregate down-ramp event on the fleet-level (see Section 9.5).

Highest 1 h up-ramps (restarts) are similar for all studied storm shutdown types. A contributor to this is that the storm shut-down slows only the shut-down and not the restart part of the power curve. However, it needs to be noted that a smoother restart operation would not remove all extreme up-ramps, as they can happen even on low wind days (see Section 8.4).

10. Statistical analysis of forecast errors

This chapter analyses the simulated forecast errors for the scenarios. The forecast errors are calculated as: $e_t = p_{t,actual} - p_{t,forecasted}$. Thus, a negative forecast error means that forecasted is larger than actual generation. All forecast errors are analysed on 15 min resolution.

The first section compares the scenarios in standardized generation, as the impact of geographical smoothening is easier to see when all data are standardized. The further sections show results mostly in GW.

10.1 Results in standardized generation

10.1.1 Day-ahead forecasts

Table 28 shows the day-ahead forecast error statistics for the different scenarios. It can be seen that the forecast error SD decreases from the BE 2018 scenario towards the 4.4 GW scenarios. This decrease is due to increased geographical distribution (on aggregate, it is easier to forecast a larger than a smaller region). Tech A and Tech B scenarios show similar statistics. The Deep storm shut-down type shows very slightly reduced likelihoods for very large forecast errors compared to 25 direct cut-off.

Table 28. Day-head forecast error statistics.

									Compared to BE 2018
			mean	SD	Prct 0.001	Prct 0.01	Prct 99.99	Prct 99.999	SD
BE 2018 (877 MW)			-0.002	0.134	-0.952	-0.747	0.741	0.971	100%
2.3 GW			-0.001	0.127	-0.791	-0.691	0.648	0.727	95%
3.0 GW	Tech A	25 m/s	-0.001	0.122	-0.731	-0.641	0.616	0.732	91%
		Moderate	-0.002	0.121	-0.739	-0.646	0.608	0.682	90%
		Deep	-0.002	0.121	-0.731	-0.639	0.607	0.682	90%
	Tech B	25 m/s	-0.001	0.121	-0.710	-0.637	0.606	0.698	90%
		Moderate	-0.001	0.121	-0.710	-0.637	0.601	0.679	90%
		Deep	-0.001	0.120	-0.710	-0.642	0.598	0.678	90%
4.0 GW	Tech A	25 m/s	-0.001	0.116	-0.702	-0.617	0.589	0.759	87%
		Moderate	-0.001	0.115	-0.721	-0.616	0.578	0.673	86%
		Deep	-0.001	0.115	-0.695	-0.607	0.570	0.673	86%
	Tech B	25 m/s	-0.001	0.116	-0.681	-0.605	0.576	0.712	87%
		Moderate	-0.001	0.115	-0.682	-0.610	0.570	0.681	86%
		Deep	-0.001	0.114	-0.681	-0.605	0.566	0.670	85%
4.4 GW	Tech A	25 m/s	-0.001	0.116	-0.700	-0.618	0.601	0.775	87%
		Moderate	-0.001	0.115	-0.710	-0.618	0.581	0.680	86%
		Deep	-0.001	0.115	-0.688	-0.604	0.571	0.671	85%
	Tech B	25 m/s	-0.001	0.117	-0.697	-0.610	0.584	0.728	87%
		Moderate	-0.001	0.115	-0.694	-0.617	0.576	0.682	86%
		Deep	-0.001	0.114	-0.677	-0.605	0.569	0.673	85%

10.1.2 Intraday forecasts

Table 29 shows the intraday forecast error statistics. It can be seen that the forecast error SD decreases from the BE 2018 scenario towards the 4.4 GW scenarios. Tech A and Tech B scenarios show similar statistics. The forecast error SDs are somewhat lower than for day-ahead (Table 28). The different storm shut-down types show similar forecast error statistics.

Table 29. Intraday forecast error statistics.

									Compared to BE 2018
			mean	**SD**	**Prct 0.001**	**Prct 0.01**	**Prct 99.99**	**Prct 99.999**	**SD**
BE 2018 (877 MW)			0.000	0.111	-0.840	-0.615	0.661	0.847	100%
2.3 GW			-0.001	0.107	-0.684	-0.584	0.559	0.666	96%
3.0 GW	**Tech A**	**25 m/s**	-0.001	0.102	-0.636	-0.551	0.525	0.607	91%
		Moderate	-0.001	0.102	-0.639	-0.553	0.525	0.608	91%
		Deep	-0.001	0.101	-0.639	-0.553	0.525	0.607	91%
	Tech B	**25 m/s**	-0.001	0.102	-0.611	-0.543	0.523	0.606	91%
		Moderate	-0.001	0.101	-0.614	-0.546	0.526	0.606	91%
		Deep	-0.001	0.101	-0.616	-0.548	0.525	0.606	91%
4.0 GW	**Tech A**	**25 m/s**	-0.001	0.097	-0.623	-0.539	0.511	0.607	87%
		Moderate	-0.001	0.096	-0.611	-0.530	0.503	0.602	87%
		Deep	-0.001	0.096	-0.607	-0.524	0.493	0.561	86%
	Tech B	**25 m/s**	0.000	0.097	-0.607	-0.524	0.511	0.589	87%
		Moderate	0.000	0.096	-0.626	-0.523	0.508	0.599	86%
		Deep	0.000	0.096	-0.602	-0.517	0.494	0.559	86%
4.4 GW	**Tech A**	**25 m/s**	0.000	0.097	-0.643	-0.549	0.529	0.638	87%
		Moderate	-0.001	0.096	-0.620	-0.538	0.505	0.602	86%
		Deep	-0.001	0.096	-0.614	-0.523	0.495	0.563	86%
	Tech B	**25 m/s**	0.000	0.098	-0.615	-0.539	0.523	0.621	88%
		Moderate	0.000	0.096	-0.641	-0.535	0.514	0.622	87%
		Deep	0.000	0.096	-0.613	-0.522	0.495	0.562	86%

10.1.3 Latest forecasts

Table 30 shows the “Last” forecast error statistics for the scenarios. It can be seen that the forecast error SD decreases from the BE 2018 scenario towards the 4.4 GW scenarios; the reduction is slightly larger than for the day-ahead and intraday forecast errors. Tech A and Tech B scenarios show similar statistics. The Deep storm shut-down type shows slightly reduced likelihoods for very large forecast errors compared to 25 direct cut-off.

Table 30. “Last” forecast error statistics.

									Compared to BE 2018
			mean	**SD**	**Prct 0.001**	**Prct 0.01**	**Prct 99.99**	**Prct 99.999**	**SD**
BE 2018 (877 MW)			0.001	0.072	-0.669	-0.490	0.554	0.726	100%
2.3 GW			0.009	0.071	-0.587	-0.429	0.490	0.650	98%
3.0 GW	**Tech A**	**25 m/s**	0.008	0.064	-0.538	-0.388	0.442	0.608	88%
		Moderate	0.008	0.063	-0.519	-0.389	0.441	0.576	88%
		Deep	0.008	0.063	-0.524	-0.382	0.436	0.577	87%
	Tech B	**25 m/s**	0.010	0.064	-0.541	-0.388	0.432	0.597	88%
		Moderate	0.010	0.063	-0.519	-0.386	0.432	0.572	88%
		Deep	0.010	0.063	-0.528	-0.382	0.428	0.579	87%
4.0 GW	**Tech A**	**25 m/s**	0.007	0.057	-0.516	-0.417	0.414	0.556	79%
		Moderate	0.007	0.056	-0.488	-0.365	0.395	0.537	78%
		Deep	0.007	0.056	-0.473	-0.342	0.376	0.535	77%
	Tech B	**25 m/s**	0.011	0.058	-0.529	-0.414	0.411	0.572	80%
		Moderate	0.011	0.057	-0.494	-0.369	0.410	0.543	79%
		Deep	0.012	0.057	-0.485	-0.338	0.390	0.523	78%
4.4 GW	**Tech A**	**25 m/s**	0.006	0.057	-0.548	-0.450	0.419	0.569	79%
		Moderate	0.007	0.056	-0.497	-0.374	0.398	0.539	77%
		Deep	0.007	0.056	-0.473	-0.342	0.376	0.539	77%
	Tech B	**25 m/s**	0.011	0.058	-0.554	-0.450	0.424	0.587	80%
		Moderate	0.012	0.057	-0.505	-0.381	0.413	0.547	79%
		Deep	0.012	0.057	-0.480	-0.343	0.393	0.524	78%

10.2 Results in GW

10.2.1 Day-ahead forecasts

Table 31 shows the average number of days per year with at least one day-ahead forecast error more extreme than the given GW limit. Tech A and Tech B scenarios show similar statistics. The most extreme forecast errors are slightly less likely for the Deep storm shutdown type compared to 25 direct cut-off.

Table 31. Day-ahead forecast errors: average number of days per year with at least one event.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								1.4	22.5	139.1	221.6	221.8	138.5	20.7	0.9					
3.0 GW	Tech A	25 m/s					0.6	7.2	50.5	176.4	248.2	247.6	175.4	47.5	5.9	0.3				
3.0 GW	Tech A	Moderate					0.6	7.1	49.6	174.6	246.8	245.9	173.2	46.8	5.8	0.2				
3.0 GW	Tech A	Deep					0.6	7.0	49.5	174.2	246.7	245.9	173.0	46.4	5.6	0.2				
3.0 GW	Tech B	25 m/s					0.5	6.6	49.2	178.6	250.0	248.8	175.2	46.5	5.4	0.3				
3.0 GW	Tech B	Moderate					0.5	6.7	49.0	176.2	248.1	246.8	172.7	45.9	5.3	0.2				
3.0 GW	Tech B	Deep					0.5	6.6	48.6	175.6	247.8	246.4	172.0	45.4	5.2	0.2				
4.0 GW	Tech A	25 m/s			0.0	0.8	5.2	25.9	89.5	211.0	270.5	268.7	208.8	84.8	23.4	4.5	0.3	0.1		
4.0 GW	Tech A	Moderate			0.0	0.7	4.7	24.6	87.7	208.8	268.5	266.6	206.2	82.5	21.8	4.0	0.3	0.0		
4.0 GW	Tech A	Deep				0.6	4.5	24.2	87.1	208.4	268.3	266.4	205.8	81.6	21.3	3.7	0.2	0.0		
4.0 GW	Tech B	25 m/s			0.1	0.6	5.4	26.4	89.6	214.6	273.7	269.6	209.3	84.4	23.6	4.2	0.3	0.1		
4.0 GW	Tech B	Moderate			0.0	0.6	5.2	25.0	87.2	211.3	270.9	267.0	206.1	81.8	21.6	3.5	0.4	0.0		
4.0 GW	Tech B	Deep			0.0	0.6	4.9	24.4	86.4	210.6	270.6	266.6	205.2	80.5	20.9	3.3	0.3	0.0		
4.4 GW	Tech A	25 m/s			0.3	2.0	10.5	37.9	107.9	224.4	278.7	277.7	222.0	101.8	34.6	8.6	1.4	0.1	0.1	
4.4 GW	Tech A	Moderate			0.2	1.7	9.4	36.2	105.6	222.0	276.9	275.8	219.4	99.2	32.6	7.1	1.1	0.1	0.0	
4.4 GW	Tech A	Deep			0.2	1.5	9.0	35.8	105.0	221.5	276.7	275.6	219.1	98.2	31.9	6.8	0.9	0.1	0.0	
4.4 GW	Tech B	25 m/s			0.2	1.9	11.1	40.2	109.0	227.3	281.8	276.8	222.7	102.5	35.1	9.3	1.4	0.1	0.0	
4.4 GW	Tech B	Moderate			0.1	1.8	10.1	38.1	105.9	223.9	278.9	274.2	219.4	99.6	32.9	7.4	1.2	0.1	0.0	
4.4 GW	Tech B	Deep			0.1	1.7	9.5	37.3	104.9	223.2	278.6	273.9	218.8	98.2	31.8	6.9	1.0	0.1	0.0	

"Existing" refers to the 2.3 GW of installations.

10.2.2 Intraday forecasts

Table 32 shows the average number of days per year with at least one intraday forecast error more extreme than the given GW limit. Tech A and Tech B show similar statistics; the most extreme forecast errors are marginally less likely for the Deep storm shutdown type compared to 25 direct cut-off.

Table 32. Intraday forecast errors: average number of days per year with at least one event.

			Negative forecast error (GW)									**Positive forecast error (GW)**								
			4.0	**3.5**	**3.0**	**2.5**	**2.0**	**1.5**	**1.0**	**0.5**	**0.3**	**0.3**	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**
Existing (2.3 GW)								0.6	15.6	152.0	253.3	255.6	152.4	12.2	0.3					
3.0 GW	**Tech A**	**25 m/s**					0.0	3.5	40.9	201.4	281.6	283.7	202.9	37.2	2.2	0.0				
		Moderate					0.1	3.5	40.5	199.3	280.1	282.2	200.7	36.8	2.3	0.1				
		Deep					0.1	3.5	40.3	198.9	279.9	282.0	200.3	36.2	2.2	0.0				
	Tech B	**25 m/s**						3.2	39.6	203.1	284.6	285.9	202.8	35.5	1.9	0.0				
		Moderate					0.0	3.1	39.6	200.5	282.6	283.7	200.5	35.5	1.9	0.0				
		Deep					0.0	3.2	39.3	200.0	282.2	283.4	199.8	34.9	1.9	0.0				
4.0 GW	**Tech A**	**25 m/s**				0.1	2.4	17.8	86.2	243.3	304.2	303.1	241.5	81.6	15.2	1.8	0.1			
		Moderate				0.1	2.1	16.8	84.3	240.9	302.4	301.5	239.1	79.8	13.8	1.5	0.1			
		Deep				0.1	2.0	16.4	83.6	240.5	302.1	301.4	238.6	78.6	13.2	1.3				
	Tech B	**25 m/s**				0.1	2.3	18.1	87.5	246.9	307.6	305.4	243.8	81.7	15.2	1.5	0.1			
		Moderate				0.1	2.1	16.7	84.8	243.4	304.8	303.4	240.7	79.5	13.8	1.4	0.1			
		Deep				0.1	2.0	16.2	83.7	242.6	304.5	303.0	239.7	78.2	13.1	1.1	0.1			
4.4 GW	**Tech A**	**25 m/s**			0.0	0.9	5.7	28.8	111.3	258.8	311.4	310.6	257.0	105.0	24.9	4.2	0.5	0.1		
		Moderate			0.0	0.7	4.9	27.3	108.7	256.3	309.5	309.2	254.7	102.9	23.1	2.9	0.4	0.1		
		Deep			0.0	0.6	4.7	26.7	108.1	256.0	309.2	309.0	254.3	101.7	22.2	2.7	0.2			
	Tech B	**25 m/s**			0.0	0.8	6.1	30.4	113.4	261.1	314.4	312.3	258.4	105.7	25.5	4.6	0.3	0.0		
		Moderate			0.1	0.5	5.0	28.1	110.1	257.5	311.7	310.3	255.3	102.9	23.6	3.5	0.4	0.0		
		Deep			0.0	0.5	4.7	27.5	108.9	256.8	311.3	310.2	254.6	101.6	22.6	2.9	0.2			

"Existing" refers to the 2.3 GW of installations.

10.2.3 Latest forecasts

Table 33 shows the average number of days per year with at least one “Last” forecast error more extreme than the given GW limit. Tech A and Tech B show similar statistics; the most extreme forecast errors are slightly less likely for the Deep storm shutdown type compared to 25 direct cut-off.

Table 33. “Last” forecast errors: average number of days per year with at least one event.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								0.1	1.8	80.3	231.1	265.1	125.4	4.1	0.2					
3.0 GW	Tech A	25 m/s					0.0	0.2	6.3	128.6	268.5	290.7	179.8	11.1	0.5	0.1				
		Moderate					0.0	0.3	6.1	125.8	266.6	289.3	178.4	10.7	0.5	0.1				
		Deep					0.0	0.3	5.6	124.8	266.3	289.0	178.1	10.4	0.5	0.0				
	Tech B	25 m/s					0.0	0.3	5.7	119.9	264.0	298.5	189.1	11.0	0.6	0.1				
		Moderate					0.1	0.3	5.6	116.1	260.4	296.6	187.5	10.8	0.6	0.1				
		Deep					0.1	0.3	5.2	114.8	260.1	296.2	187.2	10.5	0.6	0.0				
4.0 GW	Tech A	25 m/s				0.0	0.3	3.6	20.2	182.9	295.0	309.7	227.8	28.5	3.1	0.5	0.1			
		Moderate				0.0	0.2	1.5	17.1	179.4	292.6	307.9	225.6	27.2	2.4	0.4	0.1	0.0		
		Deep					0.2	0.9	15.4	178.5	292.3	307.7	225.2	26.1	1.8	0.3	0.1			
	Tech B	25 m/s				0.0	0.3	3.8	18.9	161.7	286.9	320.6	251.4	36.0	3.1	0.4	0.1	0.0		
		Moderate				0.0	0.2	1.8	14.6	156.3	282.8	318.4	248.5	33.9	2.6	0.4	0.1	0.0		
		Deep					0.2	1.0	12.7	155.1	282.2	317.9	248.0	32.9	2.2	0.2	0.1	0.0		
4.4 GW	Tech A	25 m/s			0.0	0.1	1.8	5.9	29.8	212.1	305.7	317.4	248.8	45.2	5.4	1.1	0.2	0.0		
		Moderate				0.0	0.4	3.5	26.2	208.4	303.3	315.6	246.3	43.1	4.4	0.7	0.1	0.1		
		Deep					0.2	2.3	24.4	207.7	303.1	315.4	246.0	42.0	3.6	0.4	0.1	0.0		
	Tech B	25 m/s				0.2	1.5	6.4	28.0	189.9	298.8	327.5	273.9	59.4	6.6	1.2	0.2	0.1		
		Moderate			0.0	0.1	0.4	3.5	22.5	184.4	294.9	325.5	270.6	56.4	5.5	0.9	0.1	0.1		
		Deep				0.1	0.3	2.0	20.4	183.2	294.4	325.1	270.0	55.2	4.9	0.6	0.1	0.0		

“Existing” refers to the 2.3 GW of installations~~.~~

10.3 Forecast errors during high and low wind speed days

Table 34 and Table 35 show the average number of days per year with at least one day-ahead forecast error more extreme than the given GW limit with split to high and low wind speed days, respectively. Tech A and Tech B show similar statistics in both tables. For high wind speed days, the Deep type show slightly lower likelihoods for very high forecast errors compared to 25 direct cut-off. Proportionally, the high wind speed days show more extreme forecast errors (considering that they present only ~8% of the simulated days).

Similar tables are given for intraday:

- Appendix H: Intraday forecast errors for days with maximum wind speed above 20 m/s
- Appendix I: Intraday forecast errors for days with maximum wind speed below 20 m/s.

And for “Last”:

- Appendix J: Latest forecast errors for days with maximum wind speed above 20 m/s
- Appendix K: Latest forecast errors for days with maximum wind speed below 20 m/s.

Table 34. Day-ahead forecast errors: average number of days per year with at least one event when the daily max fleet-level wind speed is above 20 m/s.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								0.1	1.0	8.2	14.3	13.3	7.6	1.2	0.2					
3.0 GW	Tech A	25 m/s					0.1	0.5	3.7	12.7	17.6	17.0	12.2	3.7	0.6	0.1				
		Moderate					0.1	0.5	2.9	11.0	16.2	15.4	10.1	3.0	0.5	0.0				
		Deep					0.1	0.4	2.7	10.6	16.1	15.3	9.9	2.6	0.4	0.0				
	Tech B	25 m/s					0.0	0.4	3.1	13.9	18.6	18.1	13.0	3.6	0.5	0.1				
		Moderate					0.0	0.4	2.8	11.5	16.8	16.3	10.6	3.1	0.4	0.1				
		Deep					0.1	0.4	2.5	10.9	16.5	15.9	9.9	2.5	0.4	0.0				
4.0 GW	Tech A	25 m/s			0.0	0.2	1.0	3.0	6.9	14.8	19.0	18.7	14.8	7.4	3.2	1.1	0.1	0.1		
		Moderate			0.0	0.1	0.5	1.8	5.1	12.6	17.0	16.7	12.3	5.1	1.6	0.5	0.1	0.0		
		Deep				0.0	0.3	1.4	4.5	12.2	16.8	16.5	11.8	4.2	1.2	0.2	0.0	0.0		
	Tech B	25 m/s			0.0	0.1	0.8	3.2	7.5	16.4	20.9	20.4	15.9	7.9	3.8	1.1	0.1	0.1		
		Moderate				0.1	0.6	1.9	5.2	13.2	18.1	18.1	12.8	5.4	1.9	0.5	0.1	0.0		
		Deep				0.1	0.4	1.3	4.4	12.4	17.8	17.6	11.9	4.0	1.2	0.2	0.1	0.0		
4.4 GW	Tech A	25 m/s			0.1	0.6	1.9	4.0	8.5	15.8	19.5	19.3	15.8	8.4	4.3	2.2	0.6	0.1	0.1	
		Moderate			0.1	0.4	0.8	2.4	6.2	13.4	17.8	17.5	13.2	5.8	2.2	0.8	0.3	0.1	0.0	
		Deep				0.1	0.5	2.0	5.6	12.9	17.6	17.3	12.9	4.8	1.6	0.5	0.1	0.0	0.0	
	Tech B	25 m/s			0.1	0.5	2.0	4.8	9.5	17.6	21.8	21.2	16.8	9.3	4.8	2.8	0.5	0.1	0.0	
		Moderate			0.1	0.3	1.0	2.8	6.3	14.2	19.0	18.9	13.7	6.4	2.6	0.9	0.3	0.1	0.0	
		Deep			0.0	0.2	0.5	1.9	5.4	13.5	18.7	18.5	13.1	5.1	1.5	0.4	0.1	0.0	0.0	

15 min resolution data. Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days. “Existing” refers to the 2.3 GW of installations.

Table 35. Day-ahead forecast errors: average number of days per year with at least one event when the daily max fleet-level wind speed is below 20 m/s.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								1.3	21.5	130.8	207.4	208.5	130.9	19.5	0.8					
3.0 GW	Tech A	25 m/s					0.6	6.6	46.8	163.7	230.6	230.6	163.2	43.8	5.3	0.2				
		Moderate					0.6	6.6	46.8	163.6	230.6	230.5	163.1	43.8	5.3	0.2				
		Deep					0.6	6.6	46.8	163.6	230.6	230.5	163.1	43.8	5.3	0.2				
	Tech B	25 m/s					0.4	6.2	46.2	164.7	231.3	230.7	162.2	42.9	4.9	0.2				
		Moderate					0.4	6.2	46.2	164.6	231.3	230.6	162.1	42.8	4.9	0.2				
		Deep					0.4	6.2	46.2	164.6	231.3	230.6	162.1	42.8	4.9	0.2				
4.0 GW	Tech A	25 m/s				0.6	4.2	22.9	82.6	196.2	251.5	250.0	194.0	77.5	20.1	3.5	0.2			
		Moderate				0.6	4.2	22.9	82.6	196.2	251.5	249.9	193.9	77.4	20.1	3.5	0.2			
		Deep				0.6	4.2	22.9	82.6	196.2	251.5	249.9	193.9	77.5	20.1	3.5	0.2			
	Tech B	25 m/s			0.0	0.5	4.5	23.1	82.1	198.2	252.9	249.1	193.4	76.4	19.8	3.1	0.2			
		Moderate			0.0	0.5	4.5	23.1	82.1	198.2	252.8	248.9	193.2	76.4	19.8	3.1	0.2			
		Deep			0.0	0.5	4.5	23.1	82.1	198.2	252.8	248.9	193.2	76.4	19.8	3.1	0.2			
4.4 GW	Tech A	25 m/s			0.2	1.4	8.5	33.9	99.4	208.6	259.2	258.4	206.2	93.4	30.3	6.3	0.8	0.0		
		Moderate			0.2	1.4	8.5	33.9	99.4	208.6	259.2	258.3	206.1	93.4	30.3	6.3	0.8	0.0		
		Deep			0.2	1.4	8.5	33.9	99.4	208.6	259.2	258.3	206.1	93.4	30.3	6.3	0.8	0.0		
	Tech B	25 m/s			0.1	1.5	9.1	35.4	99.5	209.8	259.9	255.6	205.9	93.2	30.3	6.5	0.9	0.0		
		Moderate			0.1	1.5	9.1	35.4	99.5	209.7	259.9	255.4	205.7	93.2	30.3	6.5	0.9	0.0		
		Deep			0.1	1.5	9.1	35.4	99.5	209.7	259.9	255.4	205.7	93.2	30.3	6.5	0.9	0.0		

15 min resolution data. Days with maximum fleet-level wind speed below 20 m/s cover approximately 92 % of the simulated days. “Existing” refers to the 2.3 GW of installations.

10.4 Forecast errors during high ramp and storm days

10.4.1 High ramp and storm days

High ramp days are defined as days with a maximum ramp > 2 GW (either negative or positive ramp); the most extreme of the 5 min, 15 min and 1 h ramp defines the maximum ramp of the day. These days are listed for the simulations and provided to Elia (see Section 12).

For the purpose of this analysis, storm days are defined as high ramp days where max wind speed of the day is above 20 m/s and where the extreme ramp (> 2 GW) happens during the time when wind speed is above 20 m/s (this is done by identifying the first and last time step of the day when wind speed is > 20 m/s; if for a while wind speed drops below 20 m/s, it is still considered part of storm event). The storm days are also listed and provided to Elia (see Section 12).

Average days per year of the high ramp and storm days are given in Table 36. For the BE 4.0 and BE 4.4 GW scenarios, where the additional installations constitute a significant share of the total fleet, the Deep type shows significantly less storm days with high ramp compared to the 25 direct cut-off shutdown type; even though wind speeds are the same for both storm shut-down types, the Deep type experiences less days with high ramp. This is in line with Table 27: the likelihood of higher than 2 GW ramp is reduced for Deep compared to 25 direct cut-off. In Table 36, Tech B shows some increase in the average number of days per year compared to Tech A.

Table 36. Average number of high ramp and storm days per year.

			Average number of days per year	
			High ramp days	**Storm days with high ramp**
3.0 GW	**Tech A**	**25 m/s**	1.2	0.3
		Moderate	1.3	0.4
		Deep	1.2	0.3
	Tech B	**25 m/s**	1.2	0.3
		Moderate	1.3	0.3
		Deep	1.2	0.3
4.0 GW	**Tech A**	**25 m/s**	7.1	2.8
		Moderate	5.8	1.5
		Deep	4.8	0.5
	Tech B	**25 m/s**	7.0	2.6
		Moderate	6.1	1.7
		Deep	5.1	0.7
4.4 GW	**Tech A**	**25 m/s**	12.7	4.5
		Moderate	10.4	2.1
		Deep	8.9	0.6
	Tech B	**25 m/s**	13.8	5.5
		Moderate	10.7	2.5
		Deep	9.1	0.8

10.4.2 Daily extreme forecast errors during high ramp days

Figure 46 shows the distributions of min and max forecast errors of the day for all simulated days, and for high ramp days (ramp > 2 GW) for BE 4.4 GW Tech A. It can be seen that for all forecast horizons, the high ramp days show increased likelihood for high forecast error. For the "Last" horizon, this impact is very significant.

In Figure 46, the distributions of min and max errors of all days for "Last" are more skewed than for day-ahead and intraday: this indicates that while on average "Last" shows lower forecast errors than DA or intraday (Table 30 vs. Table 28 and Table 29), there are some days when the "Last" forecasts show high errors. The distributions of the daily min and max forecast errors on high ramp days indicate that those large forecast errors are more likely to happen during high ramp days.

Table 37 shows that high (> 40 % of installed capacity) negative and positive DA forecast errors are more likely during high ramp days. The Deep type shows significantly lower forecast errors during high ramp days compared to 25 direct cut-off.

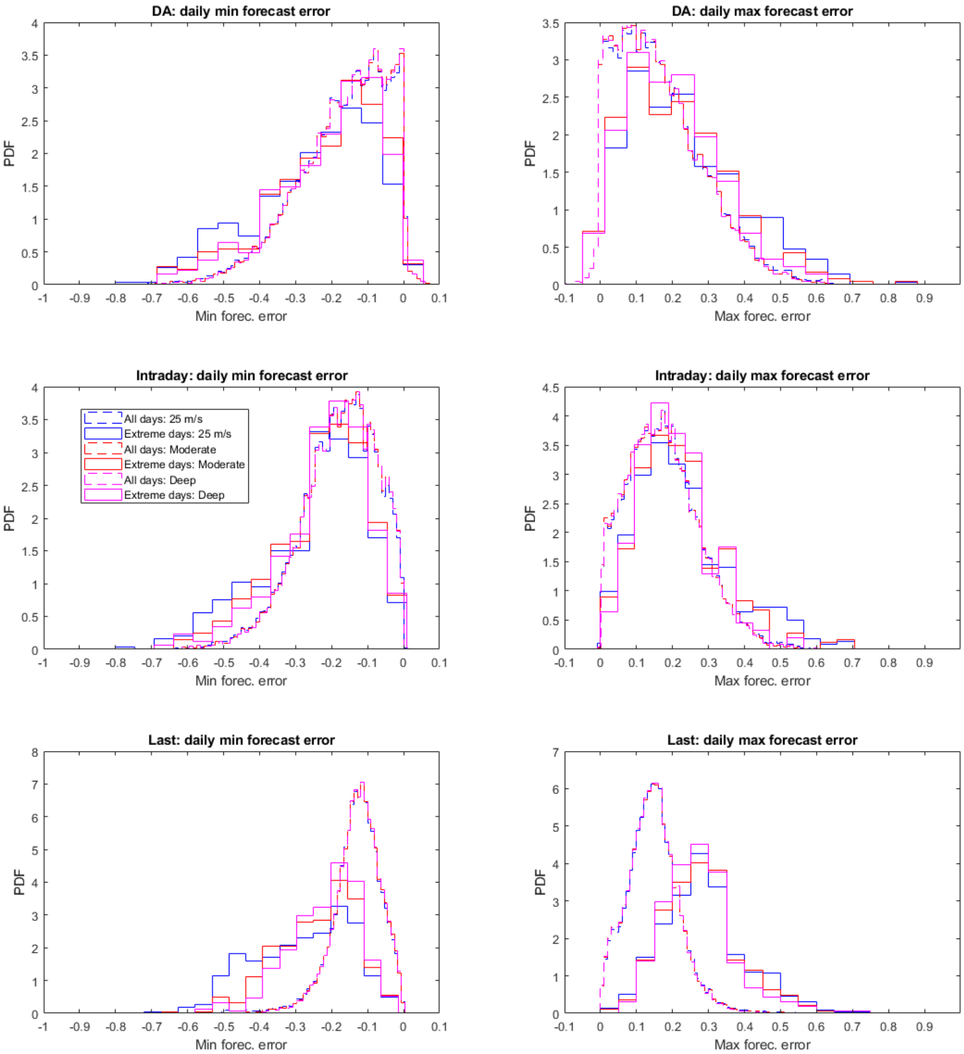


Figure 46. Distributions of max and mix forecast error of the day for all simulated days and for high ramp days (noted "extreme days" in the figure) for BE 4.4 GW Tech A.

Table 37. Share of days with maximum day-ahead forecast error below -0.4 or above 0.4 in standardized generation; comparison of all days and high ramp days.

			Number of days		Share of days with forec. err. < -0.4		Share of days with forec. err. > 0.4	
			All days	High ramp days	All days	High ramp days	All days	High ramp days
4.0 GW	**Tech A**	**25 m/s**	13514	262	5%	18%	5%	16%
		Moderate	13514	216	5%	13%	4%	12%
		Deep	13514	179	5%	12%	4%	7%
	Tech B	**25 m/s**	13514	259	5%	14%	5%	15%
		Moderate	13514	225	5%	13%	4%	12%
		Deep	13514	189	5%	12%	4%	8%
4.4 GW	**Tech A**	**25 m/s**	13513	469	5%	19%	5%	15%
		Moderate	13513	383	5%	12%	4%	11%
		Deep	13513	328	5%	11%	4%	8%
	Tech B	**25 m/s**	13513	511	6%	19%	5%	16%
		Moderate	13513	396	5%	15%	4%	11%
		Deep	13513	336	5%	13%	4%	8%

10.4.3 Daily extreme forecast errors during storm days

Figure 47 shows the distributions of min and max forecast errors of the day for all simulated days and for storm days for BE 4.4 GW Tech A. It can be seen that for all forecast horizons, the storm days show significantly increased likelihood for high forecast error; however, the estimation of forecast error distributions for storm days is challenging due to small number of days falling into the storm definition (see Section 10.4.1), as can be seen in Table 36. An example of a storm case with large DA forecast error can be seen in Figure 48; there is significant forecast error both during the shut-down and the restart part of the event.

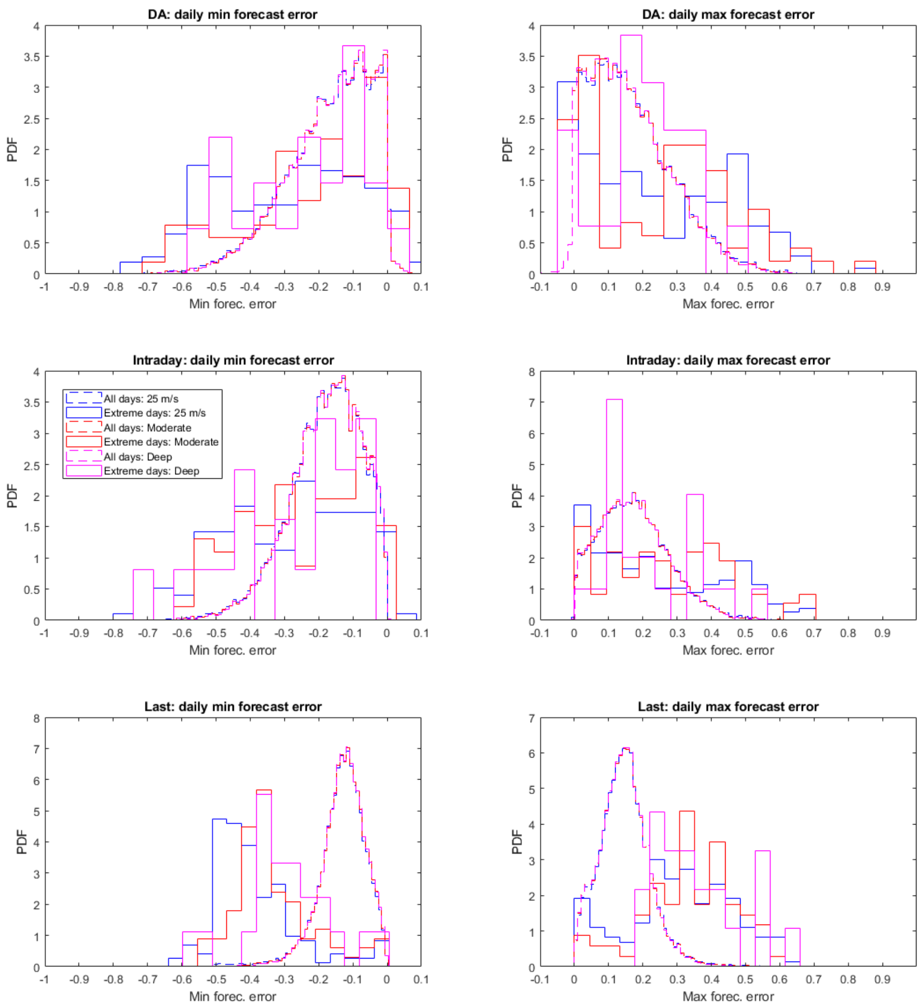


Figure 47. Distributions of max and mix forecast error of the day for all simulated days and for storm days with high ramp (noted "extreme days" in the figure) for BE 4.4 GW Tech A.

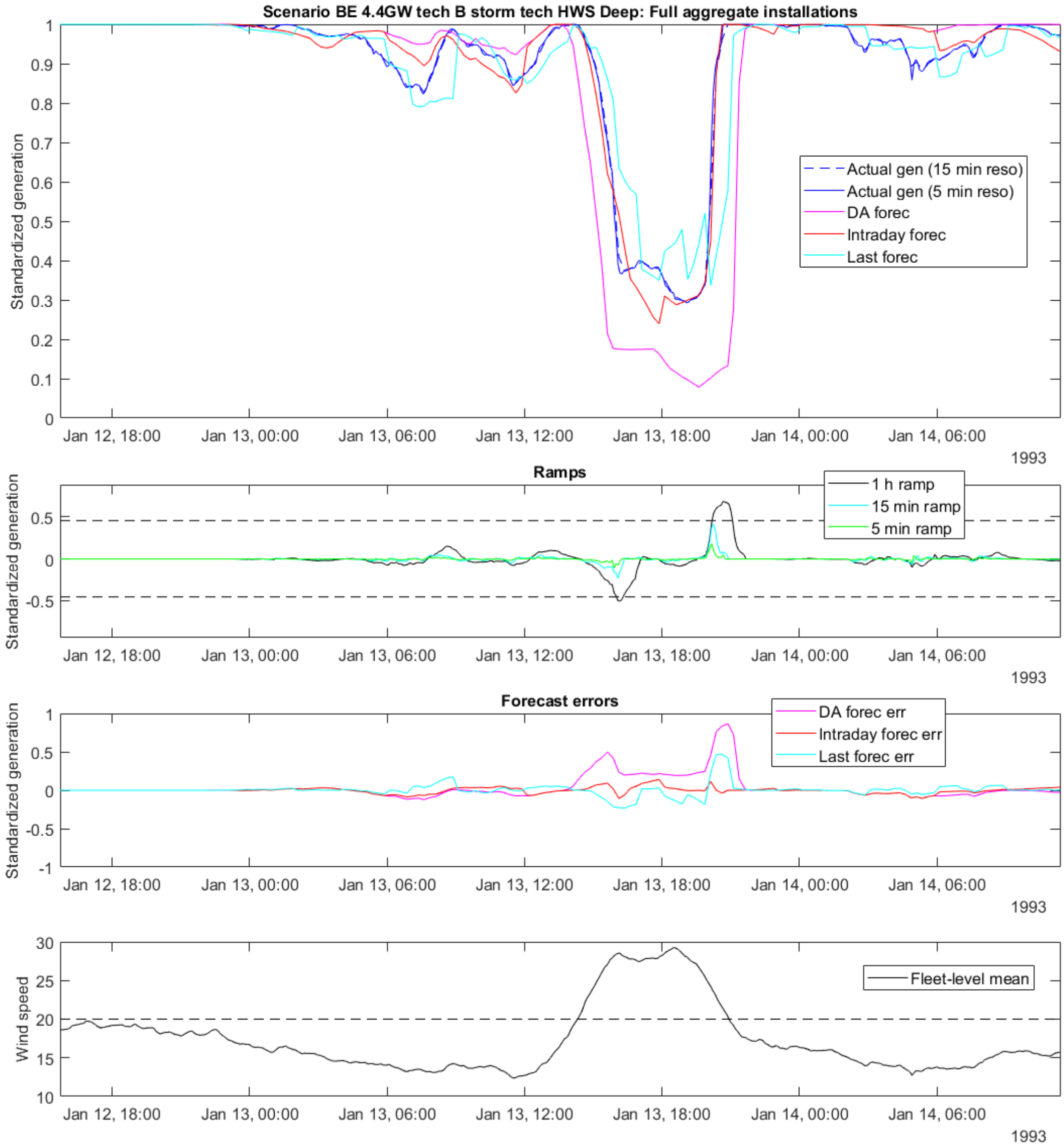


Figure 48. The time period which includes the largest simulated day-ahead (DA) forecast error for the BE 4.4. GW Tech B Deep scenario.

10.5 Conclusions on forecast errors

The fleet-level SD of standardized forecast errors decrease from the BE 2018 installations towards the 4.4 GW scenarios. This is driven by increased geographical spread of installations (no change in the forecasting accuracy of a single OWPP was assumed).

Large forecast errors are more likely during high wind speed days (fleet-level max wind speed > 20 m/s). The Deep type shows slightly lower forecast errors during high wind speeds days compared to 25 direct cut-off.

Days with high ramps (> 2 GW) show higher forecast errors, especially for “Last” forecasts. Storm days (high max wind speed and ramp > 2 GW) show higher forecast errors; however, due to relatively small amount of storm days, the estimation of forecast error distributions is challenging.

It needs to be noted that forecasts are more difficult to simulate than actual generation, as the target is not to replicate the variability due to weather, but to try to represent the forecasts by the Elia's forecast provider and to then estimate forecast behaviour in future scenarios. For this reason, the results presented for forecasts and forecast errors for the extended capacity scenarios need to be taken as representing average changes in the forecast errors resulting from different geographical installation distributions and storm shutdown technologies. The actual simulated forecast and forecast error values for an individual event are stochastic, and can be high or low due to randomness.

11. Statistical analysis on imbalance

This chapter analyses the individual BRP's imbalances and the system level imbalances based on data from the real system operation in 2018 and 2019. It includes statistical characteristics of the imbalances as well as correlations between wind power and imbalance.

11.1 Data

11.1.1 Variables

As an input for the analysis, time series with a joint 15 minutes resolution are made available by Elia for the following variables of each BRP

- Wind power production
- Wind power day ahead forecast
- Wind power intraday forecast
- Wind power last forecast
- Wind power day ahead forecast error
- Wind power intraday forecast error
- Wind power last forecast error
- Imbalance

Time series of system imbalance is also available with 15 minute resolution.

Figure 49 shows an example of wind power production, forecasts, forecast errors and imbalance. The example is chosen because it shows a clear correlation between forecast errors and imbalances, but also that there are other causes for BRP imbalances.

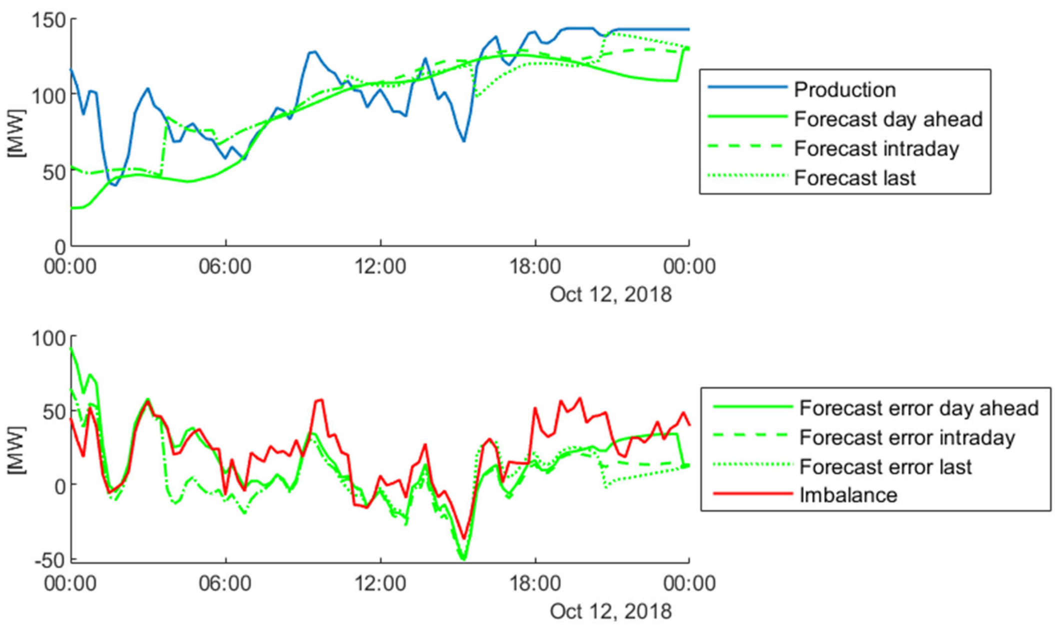


Figure 49. Example of wind power, forecasts, forecast errors and imbalance.

11.1.2 BRPs

Wind power generation and wind power forecasts are logged for the individual wind farms, but imbalances are registered at BRP level. Therefore, the contributions from wind farms to wind power generation and forecasts is summed up per BRP.

It is chosen to perform the analyses on the latest data from January 2018 to October 2019 where the installed offshore wind power capacity is increasing from 877 MW to 1535 MW. This public version of the report will show anonymized results for four BRPs operating offshore wind power plants in the Belgium system.

11.1.3 BRP sums and system level

Figure 50 shows time series of the total offshore wind power production and installed capacity in 2018-19. The installed capacity is increased from 877 MW in the beginning of 2018 to 1548 by the end of 2019.

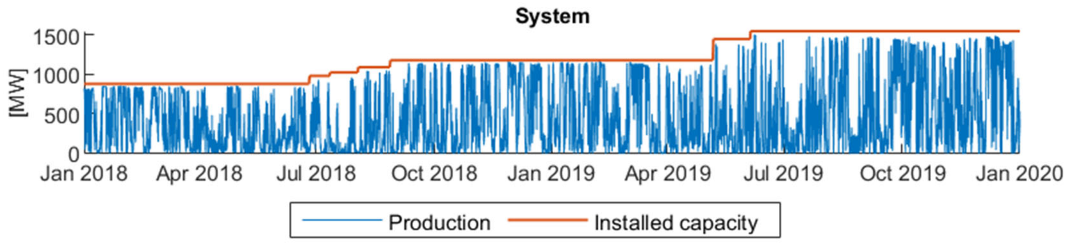


Figure 50. Offshore wind power production and capacity in Elia system 2018-19.

In order to make system level analyses in periods with fixed installed capacity, this study defines 2 data periods listed in Table 38. The table lists the included wind farms, the installed capacity and the period time for data in each data period.

Table 38. Main data for analyses periods at system level.

Period #	Installed capacity [MW]	Data period time	
		Start time	**End time**
1	877	System data: 01/01/2018 00.00 BRP sum data: 01/03/2018 00.00	25/06/2018 23.45
2	1178	01/09/2018 00.00	06/05/2019 23.45
3	1535	01/06/2019 00.00	31/10/2019 23.45

The reason why the start times in period 1 are different for BRP sums and system data is that some BRP imbalance data is missing in January and February 2019. Since there are 2 storm events in January 2018, it is chosen to keep January and February 2018 in the system data period

#1 and thus have this difference in the period times of BRP sum data period #1 and System data period #1.

11.1.4 Event subsets

The statistical analyses on imbalances is first performed for all the available data in the chosen periode with constant installed power. Subsequently, the same statistical analyses are repeated on subsets of the data in order to quantify the impact of high forecast errors, extreme ramping events and storm events on imbalances.

For each data period, the following data subsets are created:

- **10% highest forecast error days**: Those subsets are derived independently for each of the chosen datasets. First, the highest offshore wind power forecast errors is calculated during each day, as the difference between the maximum forecast error and minimum forecast error during the day. In the calculation of maximum and minimum forecast errors, day-ahead, intraday and last forecasts are included, although it is expected that the day-ahead forecast error normally is the largest. Then the days are sorted with respect to the forecast errors, and the days with the 10% highest forecast errors are selected for this subset.
- **20% highest forecast error days**: Those subsets are identified and selected using the same methodology as for 10% highest forecast errors but including the double amount (20%) of the highest forecast errors.
- **Extreme ramping events**: Those subsets are identified jointly at the system level in the general 2018-19 period. First, the wind power generation is normalized with the installed capacity during the period. Then the maximum (15 minutes) ramp rate is identified for each day, and days with more than 0.4 (i.e. 40%) ramp rates are selected for this subset.
- **Storm events**: Those subsets are identified jointly at the system level in the general 2018-19 period. The storm events were identified using the same algorithm which was applied to identify high wind speed events on the simulated data in clause 9.3.1. This method uses the wind speed from the MOG I platform to identify the high wind speed events. Those wind speeds are measured on the WINDSNELHEID meteorological mast which is located Easting x=490894.62 and Northing y=5714599.33 m. The height of the sensor is 43.96m above the see level which is lower than the hub heights of the wind turbines. Therefore, a simple wind shear correction has been applied to estimate wind speed at wind turbine hub height. Finally, only storm events with more than 40% ramps are selected.

With the applied storm event approach, only three storm events with power ramp downs greater than 40% were identified in 2018-19. The 40% threshold has been chosen by Elia because it conservatively matches a 2 GW ramp down of a 4.4 GW fleet. The three storm events are listed in Table 39.

Table 39. Storm events above 40%.

Start time	End time	Pmin	PFEmin	PFEmax
03/01/2018 00.35	03/01/2018 16.00	0.047	-0.735	0.420
18/01/2018 03.25	18/01/2018 10.35	0.016	-0.432	0.470
10/03/2019 11.25	10/03/2019 21.55	0.051	-0.530	0.262

Table 40 and Table 41 show the number of events for BRP sum analyses and system level analyses respectively. The reason why there are less BRP sum events than system events in the first row is the missing BRP imbalances data as explained in 11.1.3.

Table 40. Number of events for BRP sum analyses

Offshore wind capacity [MW]	10% highest forecast errors [# days]	20% highest forecast errors [# days]	Extreme ramps [# days]	Storms [# events]
877	12	23	17	0
1535	15	31	32	0

Table 41. Number of events for system analyses

Offshore wind capacity [MW]	10% highest forecast errors [# days]	20% highest forecast errors [# days]	Extreme ramps [# days]	Storms [# events]
877	18	35	29	2
1535	15	31	32	0

11.2 Imbalance statistics

11.2.1 Individual BRP imbalances

The statistical probability density functions (PDFs) of the individual BRPs imbalances was analysed and presented in a confidential version of this report to Elia. This analysis showed very different probability density functions, but we cannot disclose the results in this public report without the risk of breaking confidentiality.

The analyses included the PDFs for all available data, for the high forecast error events ramping event and storm events subsets described in 11.1.4. In general, the tails of the PDFs of the subsets were longer than the tails for distribution of all available data indicating that the imbalances were statistically higher in the subsets than in all data. This was however not visible for storm events, which is most likely because the amount of data in this subset is very limited.

Another observation was that the width of the different BRPs PDFs were significantly different. The primary reason for this is the difference in the capacity operated by the BRPs besides the offshore wind farm.

It should also be noted that the PDFs do not show if the BRP imbalances are increasing or decreasing the total system imbalance. This requires correlation analyses as done in 11.4.

11.2.2 BRP sums imbalances

Figure 51 shows the PDFs of the imbalances of the BRP sums defined in 11.1.3. Comparing to the individual BRP imbalances in the confidential version of this report, it was clearly observed that the PDFs of the BRP sums are significantly wider than the individual BRP PDFs, meaning that the BRP sum imbalances are statistically significantly larger than the individual BRP imbalances. This is as expected because the BRP sum imbalances include contributions from all 5 BRPs.

Table 42 shows the 0.1 % percentiles and 99.9 % percentiles of the imbalances of the BRP sums. For those aggregated BRP sums, the impact of the extreme ramping and high forecast error events is even more distinct than for the individual BRPs.

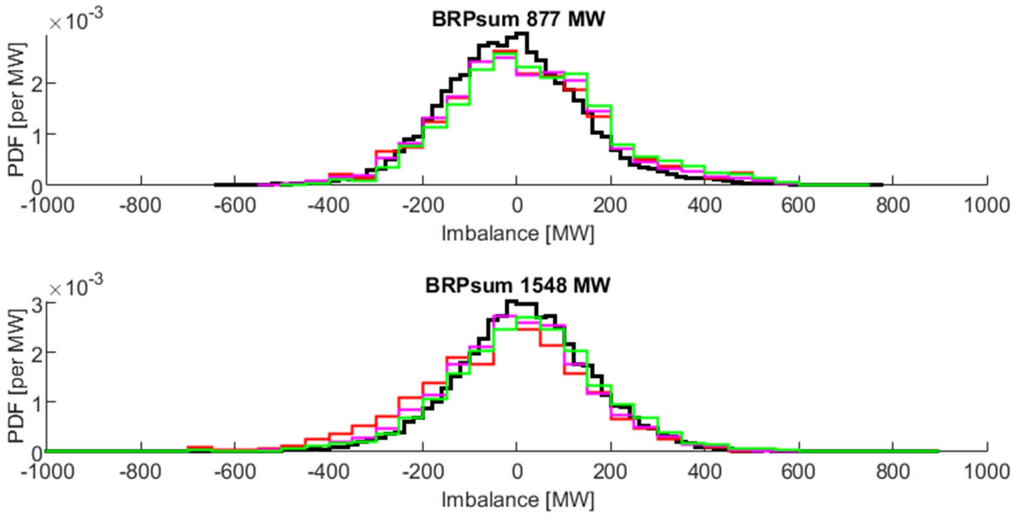


Figure 51. Probability density function for BRP sum imbalances

Table 42. 0.1 % and 99.9 % percentiles of BRP sets imbalances [MW]. Data for storms is not statistically significant.

Capacity [MW]	All valid data [MW]		FE > 10 % [MW]		FE > 20 % [MW]		Ramp > 40 % [MW]		Storm > 40 % [MW]	
Prct [%]	**0.1**	**99.9**	**0.1**	**99.9**	**0.1**	**99.9**	**0.1**	**99.9**	**0.1**	**99.9**
877	-514	513	-499	481	-508	531	-468	550		
1548	-691	553	-899	612	-968	597	-961	621		

11.2.3 System imbalances

Figure 52 shows the PDFs of the system imbalances. Comparing to the PDFs of the BRP sums in Figure 51, it is observed that the system imbalance PDF are a little wider, which is expected because the system imbalance also includes other contributions than the 5 offshore wind BPRs.

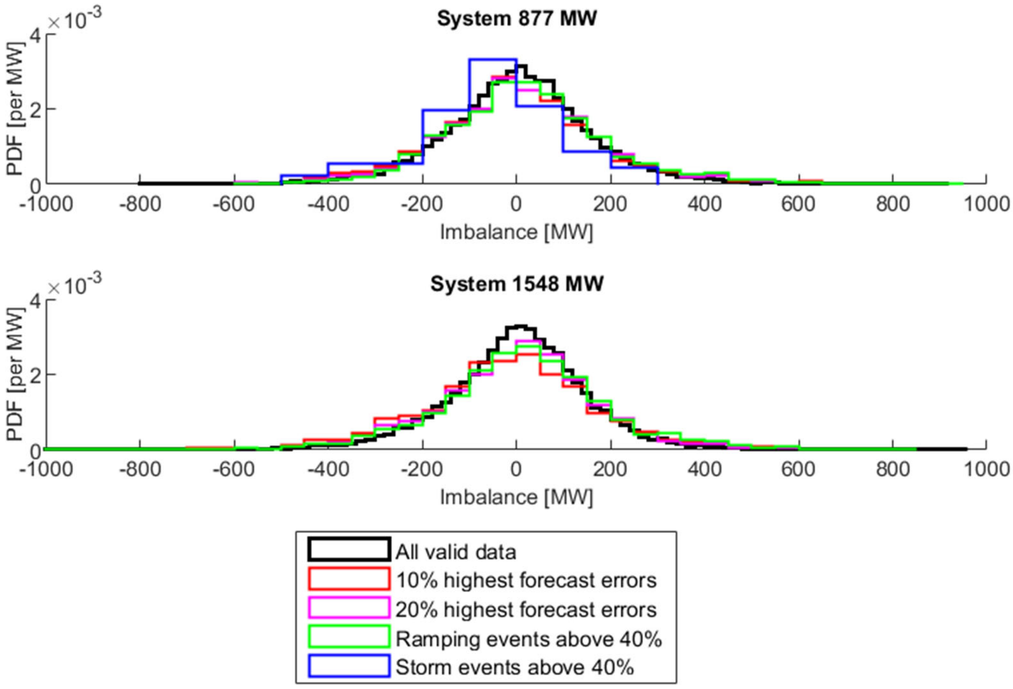


Figure 52. Probability density function for system imbalances

Table 43 shows the 0.1 % percentiles and 99.9 % percentiles of the system imbalances defined in 11.1.3. Those numbers confirm that the absolute values of the percentiles are generally larger for system imbalances than for the BRP sums above. This is also expected because the system imbalance included more contributions than the sum of the 5 offshore BRP imbalances.

Table 43. 0.1 % and 99.9 % percentiles of system imbalances [MW]. Data for storms is not statistically significant.

Capacity [MW]	**All valid data [MW]**		**FE > 10 % [MW]**		**FE > 20 % [MW]**		**Ramp > 40 % [MW]**		**Storm > 40 % [MW]**	
Prct [%]	**0.1**	**99.9**	**0.1**	**99.9**	**0.1**	**99.9**	**0.1**	**99.9**	**0.1**	**99.9**
877	-624	624	-574	724	-565	692	-564	727	-415	219
1548	-731	601	-1228	756	-1113	673	-1104	718		

11.3 Imbalance versus wind power capacity

11.3.1 Correlations between wind powers and imbalances

Figure 53 shows the correlation coefficients between wind power and imbalance for the 2 BRP sum sets, plotted as a function of the installed capacity in each of the BRP sets. The correlation coefficients are shown for wind power production, wind power forecasts and wind power forecast errors. The reason why this is straight lines is that only two periods are included in this public version.

The figure first of all shows that the correlation coefficients of the forecast errors are higher than the correlation of pure production and forecasts, which is also expected because the forecasted wind power is expected to be balanced already in the spot market. This tendency is also visible from the example time series in Figure 49.

Finally it is observed that the correlation between forecast errors and imbalances in Figure 53 does not show any no significant dependency on the installed offshore wind power capacity.

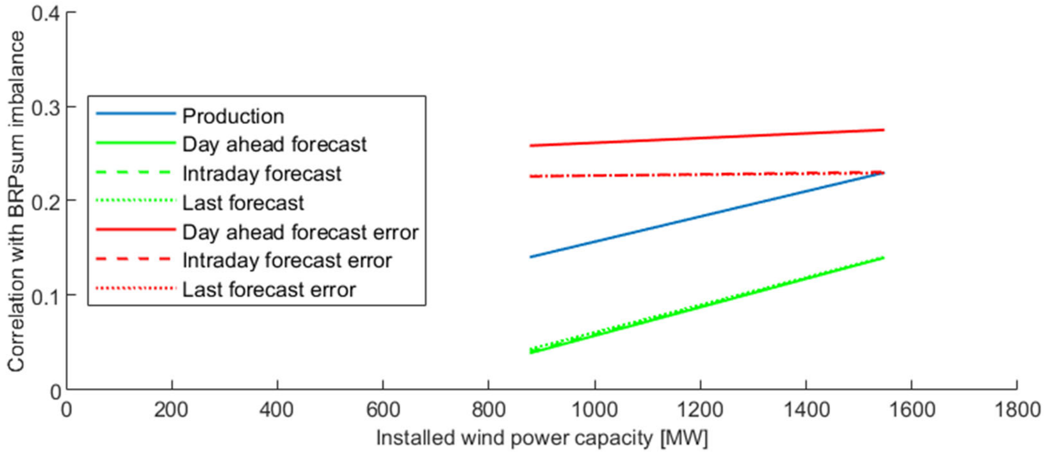


Figure 53. Correlation coefficients between wind power and imbalance for BRP sets.

Figure 54 shows the corresponding correlation coefficients with the system imbalance instead of the sum of imbalances of BRPs. The main observation is that also the system imbalance is more correlated with forecast errors than with forecasts and production. Another observation is that the correlations between last forecast error and system imbalance is increasing for increasing installed capacity, but this trend is not very strong. Finally, it is observed that the forecast error correlations with system imbalance are a little lower than correlation with sums of offshore BRP imbalances, which is as expected because the system imbalance includes other sources than the BRPs in the sets.

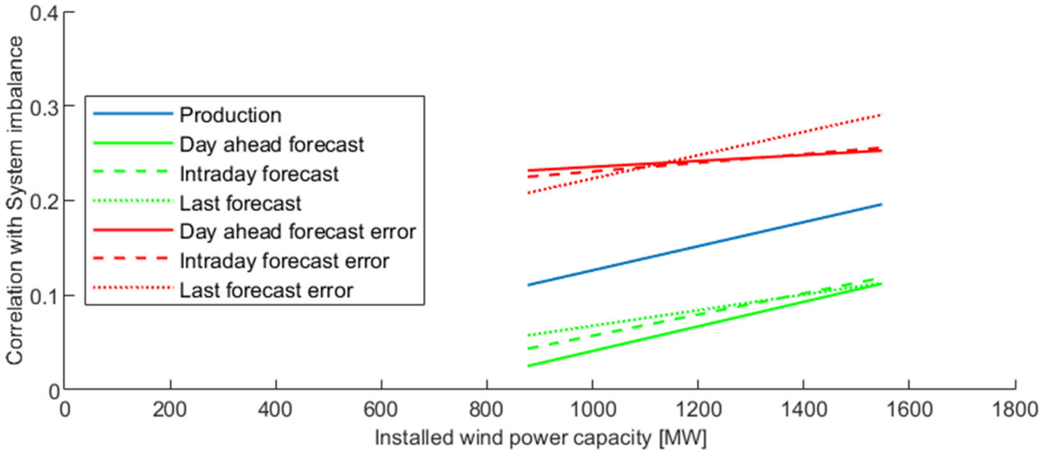


Figure 54. Correlation coefficients between wind power of BRP sets and system imbalance.

11.3.2 Forecast errors and imbalance statistics

Figure 55 shows the 0.1% and 99.9 % percentiles for system imbalance and forecast errors versus installed wind power capacity in the two selected periods. It is clearly seen how increased installed wind power increases the wind power forecast error. The impact of increased capacity on imbalances is also visible for the (lower) 0.1% percentiles but not for the (upper) 99% percentiles. It should be kept in mind that other factors than wind power forecast errors influence the system imbalance.

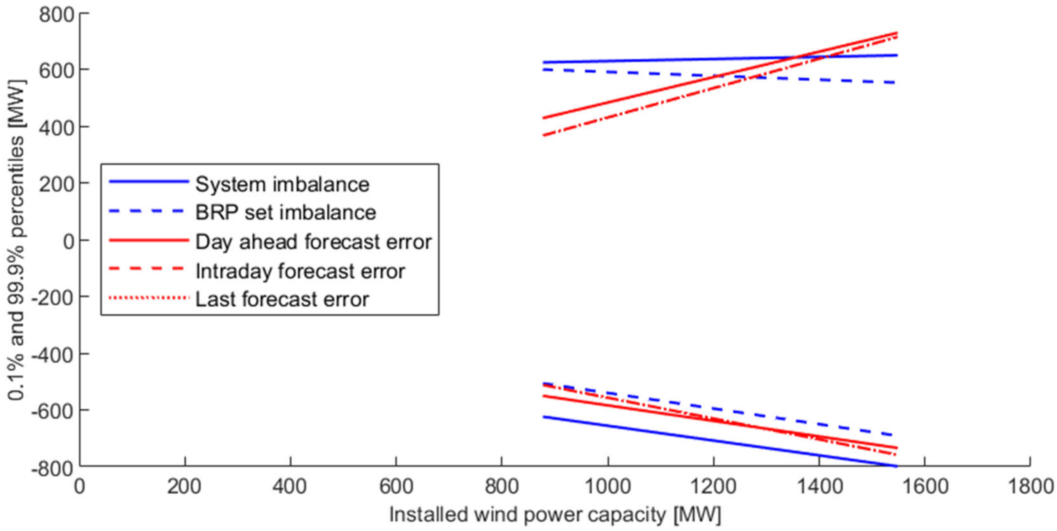


Figure 55. Observations of 0.1% (negative) and 99.9 % (positive) percentiles for system imbalance and forecast errors versus installed wind power capacity.

11.4 Correlations between forecast errors and imbalances

11.4.1 Individual BRP imbalances

Correlations can either be quantified by the correlation coefficients as it was done in 11.3.1 or by cross correlation functions which add information about the correlation when the time series are shifted against each other with a certain lag.

The cross correlation function between between BRP forecast errors and BRP imbalances are shown in Figure 56 for day-ahead forecast errors, intra-day forecast errors and last forecast errors.

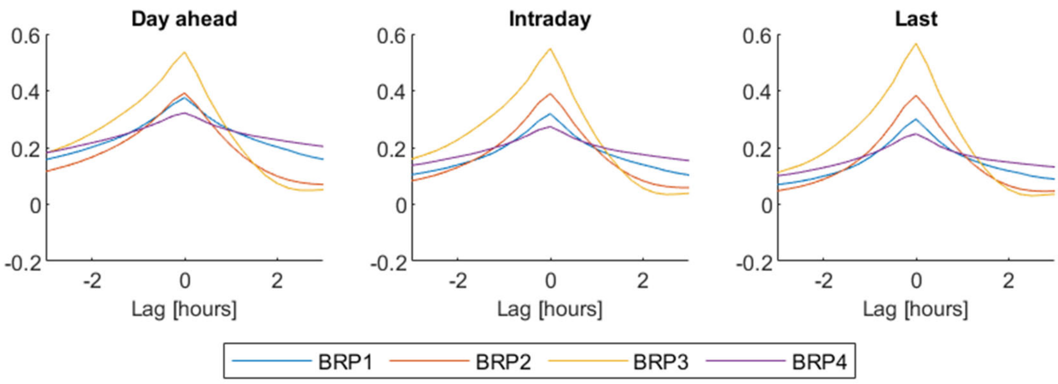


Figure 56. Cross correlation function between BRPs wind farm forecast errors and imbalances

The following observations are made:

- There is a significant difference of the correlations between forecast errors and imbalances for the different BRPs. The cross correlation function was analysed for 5 BRPs, but Figure 56 only shows the four most similar ones while the 5th had to be removed to avoid breaking confidentiality. Based on results from all 5 BRPs, we came to the general conclusion that BRPs ability to manage imbalances differ strongly between BRPs.
- The value of the cross correlation function is highest for zero lag, which confirms that the time series are properly synchronized. Initially, there was 1 sample displacement because the time in the beginning of the 15 minute value was used in one dataset and the end time in another.
- The value of cross correlation function for zero lag is per definition equal to the correlation coefficient. It is seen that the correlation coefficients are quite different for the different BRPs. The main reason for those differences is the difference in how much other generation the BRPs are operating.
- Most of the BRPs have relatively symmetrical cross correlation functions, but some converge faster to zero for positive lags. A possible interpretation of this can be that those BRPs compensate for the imbalances with an approximate response time between 15 minutes and 2 hours, but this hypothesis has not been substantiated by further analyses.

Figure 57 shows the correlation coefficients between BRPs forecast errors and imbalances for day-ahead, intraday and last forecast errors respectively. The “All valid data” correlation coefficients are calculated from BRP datasets and the other correlation coefficients are calculated from the event subsets specified in clause 11.1.4.

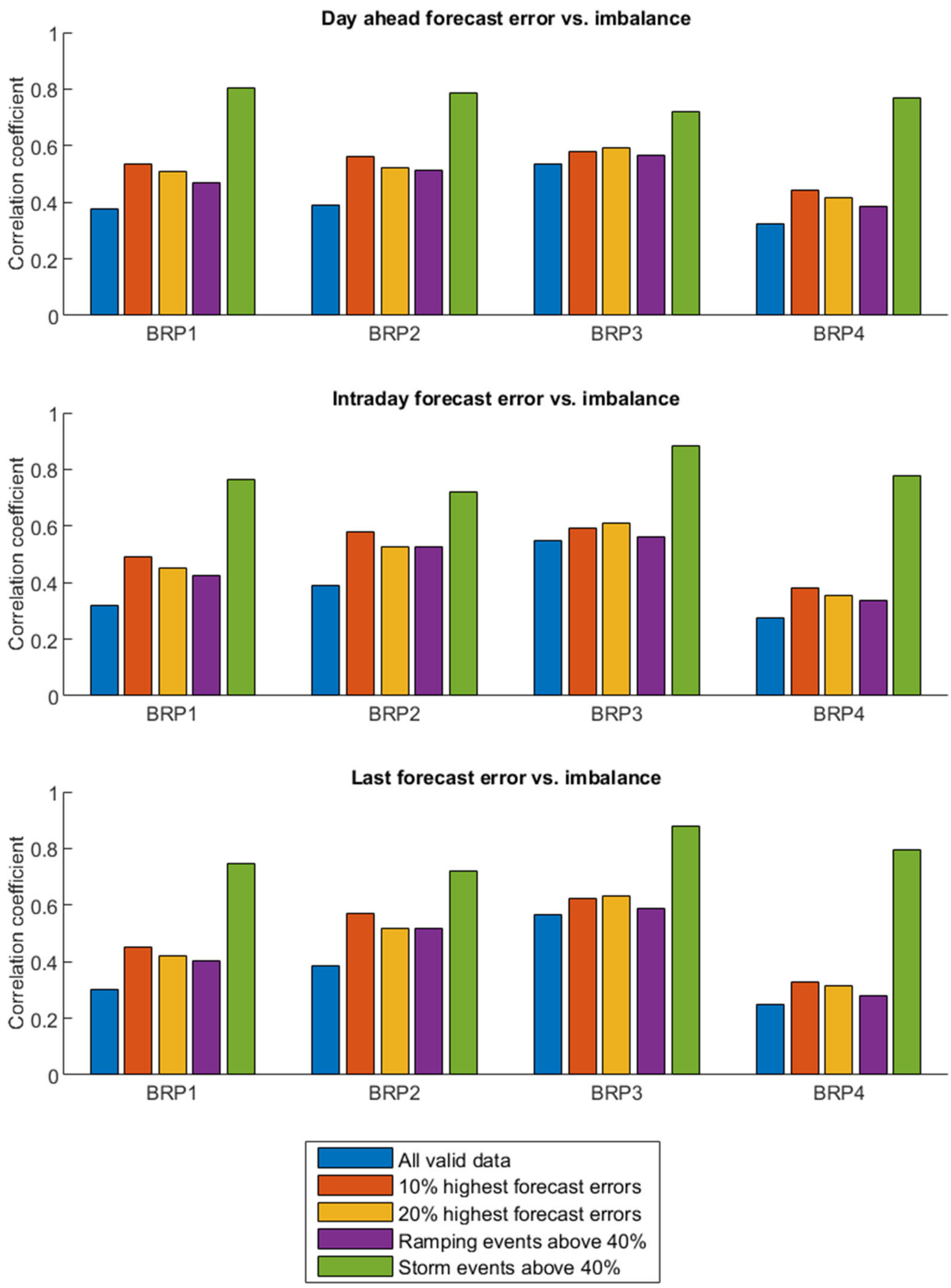


Figure 57. Correlation coefficients between BRPs forecast errors and imbalances

The correlation coefficients shown in Figure 57 are listed in Table 44.

Table 44. Correlation coefficients between BRPs forecast errors and imbalances.

BRP	All valid data			FE > 10 %			FE > 20 %			Ramp > 40 %			Storm > 40 %		
	DA	ID	Last	DA	ID	Last	DA	ID	Last	DA	ID	Last	DA	ID	Last
BRP1	0.38	0.32	0.30	0.53	0.49	0.45	0.51	0.45	0.42	0.47	0.42	0.40	0.80	0.76	0.75
BRP2	0.39	0.39	0.38	0.56	0.58	0.57	0.52	0.53	0.52	0.51	0.53	0.52	0.79	0.72	0.72
BRP3	0.54	0.55	0.57	0.58	0.59	0.62	0.59	0.61	0.63	0.57	0.56	0.59	0.72	0.88	0.88
BRP4	0.32	0.27	0.25	0.44	0.38	0.33	0.41	0.36	0.31	0.39	0.34	0.28	0.77	0.78	0.80

The main observation based on the results shown in Figure 57 and quantified in Table 44 is that the correlation coefficients are highest for the storm event subsets.

11.4.2 BRP sets imbalances

The cross correlation functions between forecast errors and imbalances for the aggregated BRP sets are shown in Figure 58 for day-ahead, intraday and last forecasts respectively. The data periods with constant installed capacity are relatively short, so the results should not be over-interpreted, but there is clearly more lag in the correlation in the 877 MW period than the 1548 MW period. The reduced lag in the 1548 MW period indicates that the forecast errors are balanced faster in that period.

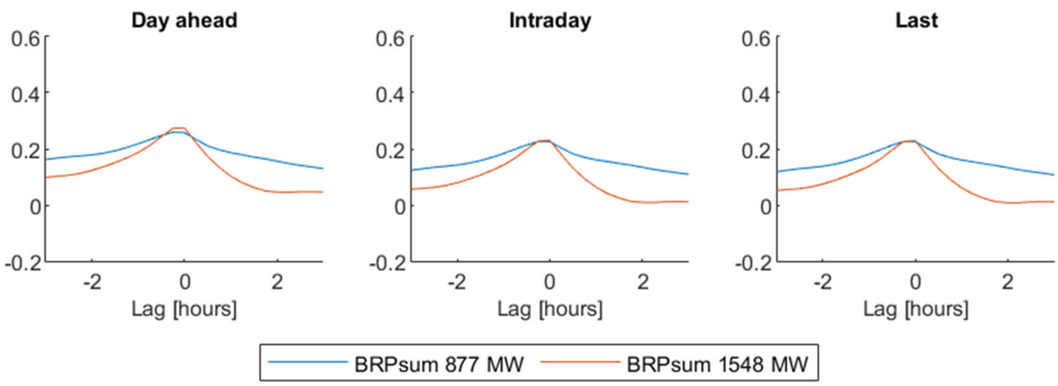


Figure 58. Cross correlation function between BRP sums forecast errors and imbalances

Figure 59 shows the correlation coefficients between aggregated BRP sets forecast errors and imbalances for day-ahead, intraday and last forecast errors respectively. The correlation coefficients shown in Figure 59 are listed in Table 45.

As for the individual BRPs, this statistical analysis is done for all available data as well as the subsets for days with highest forecast errors and extreme ramping events, and for the storm events. The impact of the extreme events is also quite significant at for this BRP sum data.

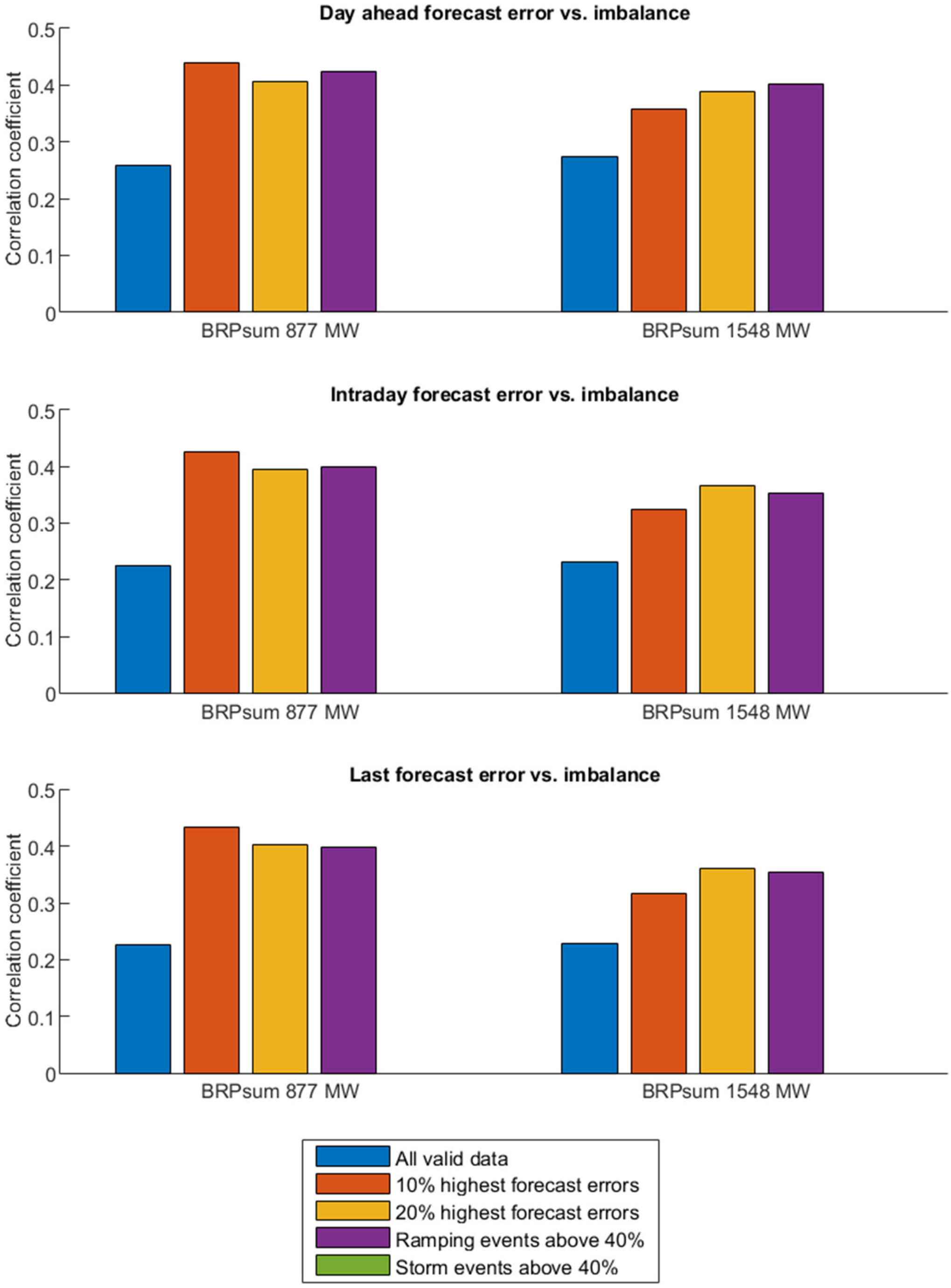


Figure 59. Correlation coefficients between offshore wind farm day-ahead forecast errors and BRP sum imbalances

Table 45. Correlation coefficients between forecast errors and imbalances of BRP sets.

Installed [MW]	All valid data			FE > 10 %			FE > 20 %			Ramp > 40 %			Storm > 40 %		
	DA	ID	Last	DA	ID	Last	DA	ID	Last	DA	ID	Last	DA	ID	Last
877	0.23	0.18	0.18	0.40	0.38	0.39	0.37	0.34	0.35	0.37	0.32	0.31			
1548	0.27	0.23	0.23	0.36	0.32	0.32	0.39	0.37	0.36	0.40	0.35	0.35			

11.4.3 System imbalance

The cross correlation functions between forecast errors and imbalances for the aggregated BRP sets are shown in Figure 60 for day-ahead, intraday and last forecasts respectively. Also here, the reduction with lack is fastest for the 1548 MW period. Another difference is that the correlation of imbalance with last forecast error is higher than for the longer forecast horizons. A positive explanation for this can be that the day-ahead and intraday balancing is working as intended.

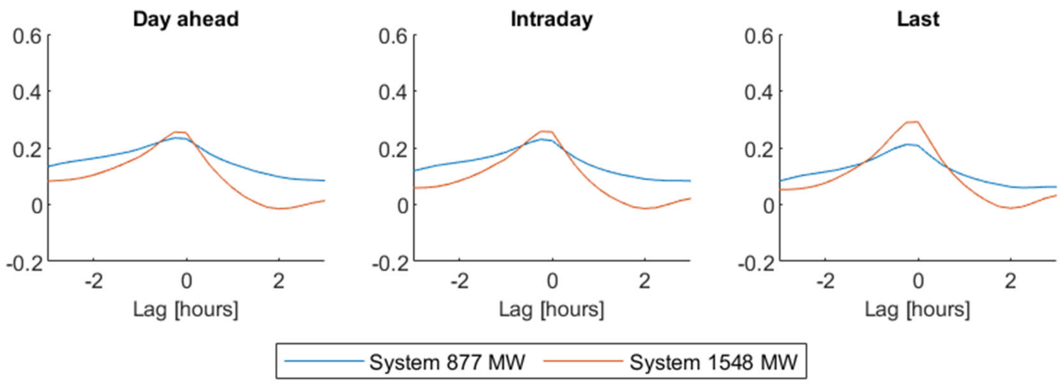


Figure 60. Cross correlation function between total wind farm forecast errors and system imbalances

The correlation coefficients between offshore wind power forecast errors and system imbalance are shown in Figure 61 and listed in Table 46.

As expected, those correlations with system imbalance are less than the correlations with BRP sum imbalances in Table 45, and as expected, this difference decreases as more BRPs are included.

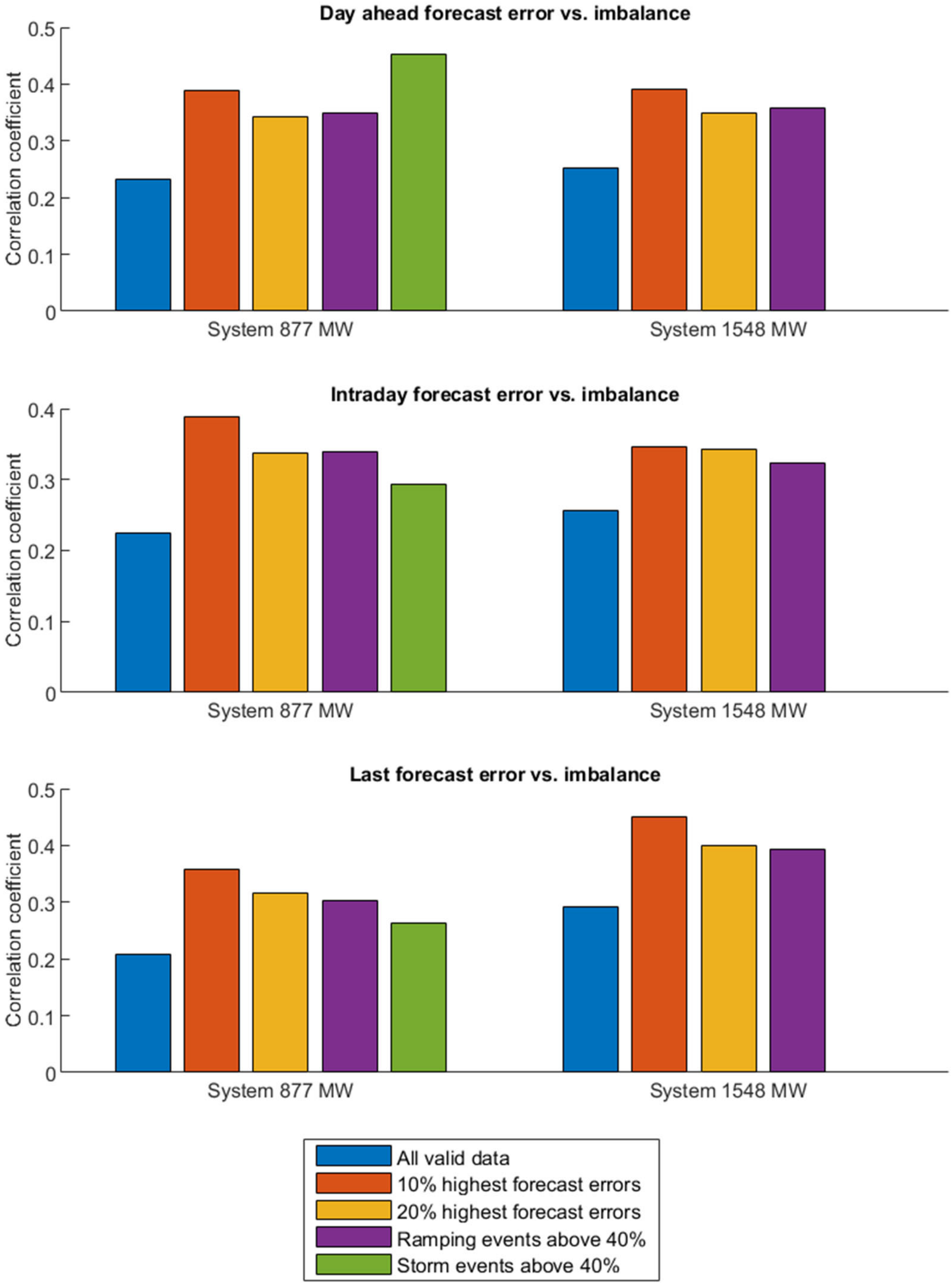


Figure 61. Correlation coefficients between offshore wind farms day-ahead forecast errors and system imbalances

Table 46. Correlation coefficients between forecast errors of BRP sets and system imbalance.

Installed [MW]	All valid data			FE > 10 %			FE > 20 %			Ramp > 40 %			Storm > 40 %		
	DA	ID	Last	DA	ID	Last	DA	ID	Last	DA	ID	Last	DA	ID	Last
877	0.23	0.23	0.21	0.39	0.39	0.36	0.34	0.34	0.32	0.35	0.34	0.30	0.45	0.29	0.26
1548	0.26	0.26	0.29	0.39	0.35	0.45	0.35	0.35	0.40	0.37	0.34	0.41			

12. Time series data provided for Elia

In addition to this report, the simulated time series from CorWind and the filtered measured data (see Section 5.4) are provided for Elia.

Simulations:
Simulated generation and wind speed data aggregated for the different scenarios, both on 5 min and 15 min resolution for 37 years are provided.

All data in the files are given in standardized generation; i.e., 1 means that the plant, or aggregate generation for the aggregate data files, is generating at full installed capacity.

Extreme ramps and storm events:
The files show how many days per year can be expected to have (at least 1) ramp event over a given limit based on the 37 years of simulations. All data are analysed in 5 min resolution (e.g., the hourly ramp means change on 5 min resolution in 1 hour). The files include sheets with all days considered, and split to days when the maximum wind speed of the day is higher or lower than 20 m/s.

The files "Extreme_ramp_events_selected" and "Storm_events_selected" report the most extreme ramp and storm cases based on the 37 years of simulations. The extreme ramp days are days when the maximum ramp (up- or down-ramp) is larger than 2 GW; the most extreme of the 5 min, 15 min and 1 h ramp defines the maximum ramp of the day. Storm days are defined as high ramp days where max wind speed of the day is above 20 m/s and where the ramp happens between the first and last time step of the day when the wind speed is above 20 m/s.

Filtered generation and forecasts for 2018-2019:
Filtered measured data from 2018 and 2019 are provided. The filtering process is explained in Section 5.4.

All data in are aggregate standardized generation; i.e., 1 means that the entire fleet (e.g., 4.4 GW of installations) is generating at full installed capacity.

As the filtering process is not valid for storm events, the times where wind speed is higher than 22 m/s have been removed from the data for future scenarios (see variable "Removed_by_DTU_because_of_storm" in the files). Wind speed data after June 2019 are not available from the OWPPs, but the wind speeds are upscaled from a single measurement point at 43.96m height above sea level from a single MET mast (WINDSNELHEID) located on the MOG platform; thus, there are more uncertainties in filtering the storm events from June 2019 onwards. As the storm events are filtered, the filter is independent of the storm shutdown technology.

It was noted that the measured forecast error data from approximately October 2019 onwards shows slightly different behaviour to the other part of the data; see Figure 62. As the data resulting from the filtering process is based on the measured data, this structural change is repeated in the data resulting from the filtering process.

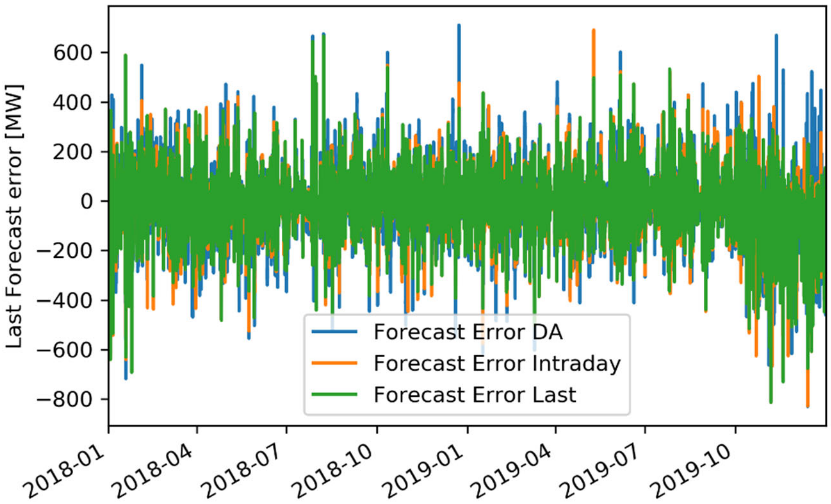


Figure 62. Forecast errors calculated from the measured data from Elia for 2018 and 2019.

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Appendix A: CFs and SDs of the additional installations

CFs and SDs of the additional installation in the different scenarios (the installations coming on top of the 2.3 GW of existing and planned installations)

			CF	SD	CF compared to BE 2018	SD compared to BE 2018
3.0 GW	Tech A	25 m/s	0.454	0.363	108%	105%
		Moderate	0.456	0.363	109%	105%
		Deep	0.457	0.363	109%	105%
	Tech B	25 m/s	0.528	0.377	126%	109%
		Moderate	0.531	0.377	127%	109%
		Deep	0.533	0.376	127%	109%
4.0 GW	Tech A	25 m/s	0.468	0.363	111%	105%
		Moderate	0.470	0.363	112%	105%
		Deep	0.471	0.363	112%	105%
	Tech B	25 m/s	0.544	0.377	130%	109%
		Moderate	0.547	0.376	130%	109%
		Deep	0.549	0.376	131%	109%
4.4 G	Te ch	25 m/s	0.468	0.363	111%	105%
		Moderate	0.470	0.363	112%	105%
		Deep	0.471	0.363	112%	105%
	Tech B	25 m/s	0.544	0.377	130%	109%
		Moderate	0.547	0.376	130%	109%
		Deep	0.549	0.376	131%	109%
	Tech A/B	25 m/s	0.519	0.370	124%	107%
		Moderate	0.522	0.370	124%	107%
		Deep	0.524	0.370	125%	107%

All values are based on the 37 years of simulations on 5 min resolution; all data are aggregate standardized generation. 100 % availability assumed.

Appendix B: 5 min ramp statistics for the additional installations

5 min ramps statistics (standardized generation) of the additional installation in the different scenarios (the installations coming on top of the 2.3 GW of existing and planned installations).

								Compared to BE 2018		
			SD	**Prct 0.01**	**Prct 0.1**	**Prct 99.9**	**Prct 99.99**	**SD**	**Prct 0.1**	**Prct 99.9**
3.0 GW	**Tech A**	**25 m/s**	0.024	-0.315	-0.130	0.131	0.302	153%	167%	169%
		Moderate	0.023	-0.236	-0.125	0.126	0.234	146%	161%	163%
		Deep	0.022	-0.224	-0.123	0.125	0.221	145%	158%	161%
	Tech B	**25 m/s**	0.024	-0.347	-0.139	0.140	0.337	158%	179%	180%
		Moderate	0.023	-0.259	-0.132	0.133	0.258	151%	170%	172%
		Deep	0.023	-0.235	-0.130	0.130	0.237	149%	168%	168%
4.0 GW	**Tech A**	**25 m/s**	0.015	-0.196	-0.080	0.080	0.180	100%	103%	103%
		Moderate	0.015	-0.129	-0.075	0.076	0.133	96%	97%	98%
		Deep	0.015	-0.119	-0.073	0.074	0.120	95%	95%	95%
	Tech B	**25 m/s**	0.016	-0.222	-0.089	0.089	0.206	104%	115%	114%
		Moderate	0.015	-0.146	-0.082	0.082	0.149	99%	105%	106%
		Deep	0.015	-0.129	-0.080	0.080	0.136	98%	103%	103%
4.4 GW	**Tech A**	**25 m/s**	0.015	-0.196	-0.080	0.080	0.180	100%	103%	103%
		Moderate	0.015	-0.129	-0.075	0.076	0.133	96%	97%	98%
		Deep	0.015	-0.119	-0.073	0.074	0.120	95%	95%	95%
	Tech B	**25 m/s**	0.016	-0.222	-0.089	0.089	0.206	104%	115%	114%
		Moderate	0.015	-0.146	-0.082	0.082	0.149	99%	105%	106%
		Deep	0.015	-0.129	-0.080	0.080	0.136	98%	103%	103%
	Tech A/B	**25 m/s**	0.016	-0.208	-0.086	0.085	0.201	102%	111%	110%
		Moderate	0.015	-0.139	-0.079	0.079	0.143	98%	102%	102%
		Deep	0.015	-0.127	-0.077	0.077	0.131	97%	100%	99%

All values are based on the 37 years of simulations on 5 min resolution; all data are aggregate standardized generation.

Appendix C: 15 min ramp statistics for the additional installations

15 min ramps statistics (standardized generation) of the additional installation in the different scenarios (the installations coming on top of the 2.3 GW of existing and planned installations).

								Compared to BE 2018		
			SD	**Prct 0.01**	**Prct 0.1**	**Prct 99.9**	**Prct 99.99**	**SD**	**Prct 0.1**	**Prct 99.9**
3.0 GW	**Tech A**	**25 m/s**	0.051	-0.688	-0.280	0.283	0.672	144%	164%	159%
		Moderate	0.049	-0.460	-0.261	0.267	0.474	138%	153%	149%
		Deep	0.048	-0.423	-0.256	0.262	0.437	137%	150%	147%
	Tech B	**25 m/s**	0.053	-0.760	-0.301	0.304	0.752	150%	177%	170%
		Moderate	0.051	-0.506	-0.277	0.285	0.522	143%	163%	160%
		Deep	0.050	-0.448	-0.271	0.277	0.474	142%	159%	155%
4.0 GW	**Tech A**	**25 m/s**	0.036	-0.422	-0.186	0.189	0.409	101%	109%	106%
		Moderate	0.035	-0.286	-0.171	0.176	0.313	98%	100%	99%
		Deep	0.034	-0.255	-0.167	0.171	0.273	96%	98%	96%
	Tech B	**25 m/s**	0.038	-0.455	-0.208	0.211	0.451	106%	122%	118%
		Moderate	0.036	-0.316	-0.187	0.191	0.338	102%	110%	107%
		Deep	0.036	-0.279	-0.181	0.185	0.304	100%	106%	104%
4.4 GW	**Tech A**	**25 m/s**	0.036	-0.422	-0.186	0.189	0.409	101%	109%	106%
		Moderate	0.035	-0.286	-0.171	0.176	0.313	98%	100%	99%
		Deep	0.034	-0.255	-0.167	0.171	0.273	96%	98%	96%
	Tech B	**25 m/s**	0.038	-0.455	-0.208	0.211	0.451	106%	122%	118%
		Moderate	0.036	-0.316	-0.187	0.191	0.338	102%	110%	107%
		Deep	0.036	-0.279	-0.181	0.185	0.304	100%	106%	104%
	Tech A/B	**25 m/s**	0.037	-0.422	-0.201	0.202	0.427	104%	118%	113%
		Moderate	0.035	-0.301	-0.181	0.183	0.327	100%	106%	103%
		Deep	0.035	-0.273	-0.176	0.178	0.294	99%	103%	100%

All values are based on the 37 years of simulations on 5 min resolution; all data are aggregate standardized generation. 15 min ramps mean change in 5 min resolution data within 3 time steps.

Appendix D: 1h ramp statistics for the additional installations

1h ramps statistics (standardized generation) of the additional installation in the different scenarios (the installations coming on top of the 2.3 GW of existing and planned installations).

								Compared to BE 2018		
			SD	Prct 0.01	Prct 0.1	Prct 99.9	Prct 99.99	SD	Prct 0.1	Prct 99.9
3.0 GW	Tech A	25 m/s	0.114	-1.000	-0.604	0.641	1.000	124%	142%	138%
		Moderate	0.110	-0.811	-0.525	0.564	0.959	120%	124%	122%
		Deep	0.109	-0.736	-0.507	0.545	0.820	119%	119%	118%
	Tech B	25 m/s	0.120	-1.000	-0.668	0.696	1.000	131%	157%	150%
		Moderate	0.116	-0.839	-0.568	0.602	0.989	126%	134%	130%
		Deep	0.114	-0.762	-0.541	0.574	0.849	124%	127%	124%
4.0 GW	Tech A	25 m/s	0.097	-0.998	-0.484	0.522	0.979	105%	114%	113%
		Moderate	0.094	-0.686	-0.436	0.474	0.783	102%	103%	102%
		Deep	0.093	-0.600	-0.419	0.457	0.666	101%	99%	99%
	Tech B	25 m/s	0.102	-1.000	-0.539	0.573	1.000	111%	127%	124%
		Moderate	0.098	-0.742	-0.473	0.511	0.858	107%	111%	110%
		Deep	0.097	-0.636	-0.452	0.490	0.721	105%	107%	106%
4.4 GW	Tech A	25 m/s	0.097	-0.998	-0.484	0.522	0.979	105%	114%	113%
		Moderate	0.094	-0.686	-0.436	0.474	0.783	102%	103%	102%
		Deep	0.093	-0.600	-0.419	0.457	0.666	101%	99%	99%
	Tech B	25 m/s	0.102	-1.000	-0.539	0.573	1.000	111%	127%	124%
		Moderate	0.098	-0.742	-0.473	0.511	0.858	107%	111%	110%
		Deep	0.097	-0.636	-0.452	0.490	0.721	105%	107%	106%
	Tech A/B	25 m/s	0.099	-0.978	-0.515	0.545	0.979	108%	121%	118%
		Moderate	0.096	-0.701	-0.458	0.488	0.779	104%	108%	105%
		Deep	0.094	-0.621	-0.439	0.469	0.695	103%	103%	101%

All values are based on the 37 years of simulations on 5 min resolution; all data are aggregate standardized generation. 1 h ramps mean change in 5 min resolution data within 12 time steps.

Appendix E: 5 min ramp statistics for days with maximum wind speed below 20 m/s

5 min ramps: average number of days per year with at least one event when the daily max fleet-level wind speed is below 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)																				
Existing (2.3 GW)										0.0	0.9	0.9								
3.0 GW	Tech A	25 m/s								0.4	2.6	2.8	0.4							
		Moderate								0.1	2.2	2.5	0.1							
		Deep								0.0	2.2	2.4	0.1							
	Tech B	25 m/s								0.4	3.1	2.5	0.4							
		Moderate								0.0	2.7	2.1	0.1							
		Deep								0.0	2.6	2.1	0.0							
4.0 GW	Tech A	25 m/s								0.6	5.6	5.7	0.6							
		Moderate								0.0	4.9	4.9	0.2							
		Deep								0.0	4.8	4.8	0.1							
	Tech B	25 m/s							0.0	0.6	7.2	6.9	0.7							
		Moderate								0.1	6.4	6.0	0.2							
		Deep								0.1	6.3	5.9	0.2							
4.4 GW	Tech A	25 m/s							0.0	0.9	9.9	10.1	1.1							
		Moderate								0.3	9.1	9.4	0.4							
		Deep								0.2	9.0	9.4	0.4							
	Tech B	25 m/s							0.0	1.3	12.6	12.4	1.2							
		Moderate								0.5	11.7	11.5	0.5							
		Deep								0.5	11.6	11.5	0.5							

Days with maximum fleet-level wind speed below 20 m/s cover approximately 92 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

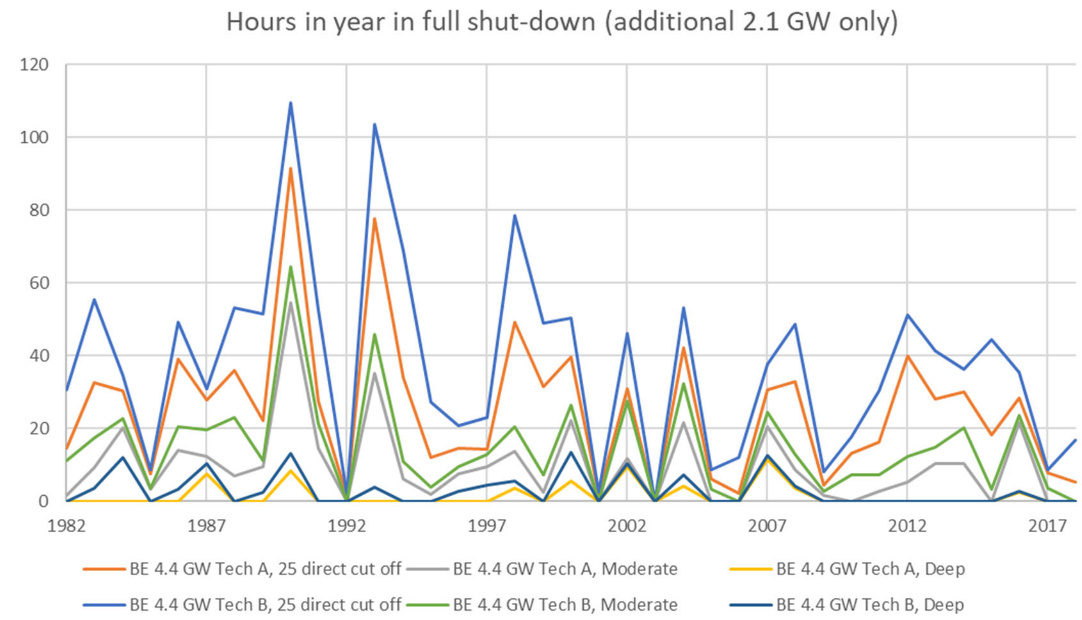
Appendix F: 15 min ramp statistics for days with maximum wind speed below 20 m/s

15 min ramps: average number of days per year with at least one event when the daily max fleet-level wind speed is below 20 m/s.

			Negative ramp (GW)									Positive ramp (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
BE 2018 (877 MW)											0.5	0.3								
Existing (2.3 GW)										5.7	63.5	72.9	6.5	0.0						
3.0 GW	Tech A	25 m/s							0.0	11.2	111.8	124.2	14.1	0.0						
		Moderate							0.0	10.9	111.6	124.1	13.7	0.0						
		Deep							0.0	10.9	111.6	124.1	13.7	0.0						
	Tech B	25 m/s							0.0	11.5	113.2	121.4	13.6	0.0						
		Moderate							0.0	11.1	113.0	121.2	13.2	0.0						
		Deep							0.0	11.1	113.0	121.2	13.1	0.0						
4.0 GW	Tech A	25 m/s							0.2	25.8	173.5	179.8	28.5	0.1	0.0					
		Moderate							0.1	25.3	173.4	179.7	28.0	0.1	0.0					
		Deep							0.1	25.2	173.4	179.7	27.9	0.1	0.0					
	Tech B	25 m/s							0.2	28.9	180.0	183.1	30.1	0.1	0.0					
		Moderate							0.1	28.4	179.7	182.8	29.5	0.1	0.0					
		Deep							0.1	28.3	179.7	182.8	29.4	0.1	0.0					
4.4 GW	Tech A	25 m/s							0.4	42.3	207.7	212.5	47.1	0.6	0.0					
		Moderate							0.4	41.9	207.6	212.5	46.5	0.6	0.0					
		Deep							0.4	41.8	207.6	212.5	46.5	0.6	0.0					
	Tech B	25 m/s						0.0	0.8	50.5	213.8	218.0	49.9	0.9	0.0					
		Moderate						0.0	0.8	50.0	213.6	217.8	49.2	0.8	0.0					
		Deep						0.0	0.8	49.9	213.6	217.8	49.1	0.8	0.0					

Days with maximum fleet-level wind speed below 20 m/s cover approximately 92 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

Appendix G: Number of hours per year in full shut-down (additional 2.1 GW only)



Appendix H: Intraday forecast errors for days with maximum wind speed above 20 m/s

Intraday forecast errors: average number of days per year with at least one event when the daily max fleet-level wind speed is above 20 m/s.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								0.0	0.9	8.3	15.5	13.6	6.8	0.6	0.0					
3.0 GW	Tech A	25 m/s						0.4	2.9	13.5	19.1	17.5	12.1	2.4	0.2					
		Moderate					0.0	0.3	2.6	11.4	17.6	15.9	10.0	2.0	0.3	0.0				
		Deep					0.0	0.3	2.3	11.1	17.5	15.7	9.5	1.5	0.2					
	Tech B	25 m/s						0.2	2.5	14.5	20.4	18.7	12.6	2.1	0.1					
		Moderate					0.0	0.2	2.5	11.9	18.3	16.6	10.4	2.0	0.2					
		Deep					0.0	0.3	2.2	11.4	17.9	16.2	9.6	1.4	0.2					
4.0 GW	Tech A	25 m/s				0.1	0.6	2.4	6.7	16.0	20.2	18.9	14.5	6.0	2.5	0.6	0.1			
		Moderate				0.0	0.3	1.4	4.8	13.6	18.4	17.2	12.2	4.2	1.0	0.3	0.1			
		Deep				0.0	0.2	1.0	4.1	13.2	18.2	17.1	11.6	3.1	0.4	0.1				
	Tech B	25 m/s				0.0	0.6	2.9	7.8	17.5	22.2	20.3	16.0	6.3	2.6	0.4	0.0			
		Moderate				0.0	0.3	1.4	5.2	14.0	19.4	18.3	12.9	4.1	1.3	0.3	0.1			
		Deep					0.2	1.0	4.1	13.2	19.1	18.0	11.9	2.8	0.5	0.1	0.0			
4.4 GW	Tech A	25 m/s			0.0	0.3	1.5	3.5	8.3	17.0	21.0	19.3	15.6	7.1	3.3	1.6	0.3	0.1		
		Moderate			0.0	0.1	0.7	2.0	5.7	14.5	19.1	18.0	13.4	5.1	1.5	0.4	0.2	0.1		
		Deep			0.0	0.1	0.4	1.4	5.1	14.2	18.9	17.8	13.0	3.9	0.6	0.2	0.0			
	Tech B	25 m/s				0.4	1.7	4.5	9.6	18.7	23.2	21.4	17.1	7.7	3.6	1.9	0.2	0.0		
		Moderate			0.0	0.2	0.7	2.2	6.5	15.1	20.4	19.4	14.1	5.0	1.8	0.8	0.2	0.0		
		Deep				0.1	0.4	1.6	5.2	14.3	20.0	19.3	13.3	3.7	0.8	0.2	0.1			

Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

Appendix I: Intraday forecast errors for days with maximum wind speed below 20 m/s

Intraday forecast errors: average number of days per year with at least one event when the daily max fleet-level wind speed is below 20 m/s.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								0.6	14.7	143.7	237.8	242.0	145.5	11.6	0.2					
3.0 GW	Tech A	25 m/s					0.0	3.2	38.0	187.9	262.5	266.3	190.8	34.8	2.0	0.0				
		Moderate					0.0	3.2	38.0	187.9	262.5	266.2	190.8	34.8	2.0	0.0				
		Deep					0.0	3.2	38.0	187.9	262.5	266.2	190.8	34.8	2.0	0.0				
	Tech B	25 m/s						2.9	37.1	188.6	264.2	267.2	190.2	33.5	1.8	0.0				
		Moderate						2.9	37.1	188.6	264.2	267.1	190.1	33.5	1.8	0.0				
		Deep						2.9	37.1	188.6	264.2	267.1	190.1	33.5	1.8	0.0				
4.0 GW	Tech A	25 m/s				0.1	1.8	15.4	79.5	227.4	283.9	284.2	227.0	75.5	12.7	1.2				
		Moderate				0.1	1.8	15.4	79.5	227.3	283.9	284.2	226.9	75.5	12.7	1.2				
		Deep				0.1	1.8	15.4	79.5	227.3	283.9	284.2	226.9	75.5	12.7	1.2				
	Tech B	25 m/s				0.1	1.8	15.2	79.6	229.4	285.4	285.1	227.8	75.4	12.5	1.1	0.1			
		Moderate				0.1	1.8	15.2	79.6	229.4	285.4	285.0	227.8	75.4	12.5	1.1	0.1			
		Deep				0.1	1.8	15.2	79.6	229.4	285.4	285.0	227.8	75.4	12.5	1.1	0.1			
4.4 GW	Tech A	25 m/s				0.5	4.3	25.2	103.1	241.8	290.4	291.2	241.3	97.9	21.6	2.5	0.2			
		Moderate				0.5	4.3	25.2	103.1	241.8	290.4	291.2	241.3	97.9	21.6	2.5	0.2			
		Deep				0.5	4.3	25.2	103.1	241.8	290.4	291.2	241.3	97.9	21.6	2.5	0.2			
	Tech B	25 m/s			0.0	0.4	4.4	25.9	103.7	242.4	291.2	290.9	241.3	97.9	21.8	2.7	0.1			
		Moderate			0.0	0.4	4.4	25.9	103.7	242.4	291.2	290.9	241.2	97.9	21.8	2.7	0.1			
		Deep			0.0	0.4	4.4	25.9	103.7	242.4	291.2	290.9	241.2	97.9	21.8	2.7	0.1			

Days with maximum fleet-level wind speed below 20 m/s cover approximately 92 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

Appendix J: Latest forecast errors for days with maximum wind speed above 20 m/s

“Last” forecast errors: average number of days per year with at least one event when the daily max fleet-level wind speed is above 20 m/s.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								0.0	0.2	5.2	13.9	18.2	9.8	0.9	0.1					
3.0 GW	Tech A	25 m/s					0.0	0.0	1.4	11.0	18.6	21.8	14.6	2.5	0.2	0.1				
		Moderate					0.0	0.1	1.1	8.3	16.8	20.3	13.3	2.1	0.2	0.0				
		Deep					0.0	0.1	0.6	7.4	16.5	20.1	13.0	1.7	0.1					
	Tech B	25 m/s						0.1	1.1	12.1	20.1	23.4	15.6	2.4	0.2	0.1				
		Moderate					0.0	0.1	1.0	8.5	16.5	21.5	14.1	2.1	0.2	0.0				
		Deep					0.0	0.1	0.6	7.2	16.2	21.1	13.7	1.9	0.2					
4.0 GW	Tech A	25 m/s					0.2	2.8	6.1	14.1	19.8	22.6	17.9	5.3	1.8	0.4	0.0			
		Moderate				0.0	0.1	0.8	3.1	10.7	17.6	20.8	15.8	4.1	1.1	0.2	0.0	0.0		
		Deep					0.1	0.2	1.4	9.9	17.2	20.6	15.4	3.0	0.5	0.1	0.0			
	Tech B	25 m/s					0.2	3.0	7.8	15.4	21.6	24.9	19.8	6.5	1.8	0.3	0.1			
		Moderate				0.0	0.1	1.0	3.5	10.1	17.5	22.7	16.9	4.5	1.3	0.3	0.1			
		Deep					0.1	0.2	1.6	8.9	17.0	22.2	16.4	3.5	0.8	0.1	0.1			
4.4 GW	Tech A	25 m/s				0.1	1.6	4.0	7.4	15.8	20.7	23.1	19.3	7.4	2.6	0.9	0.2			
		Moderate				0.0	0.2	1.6	3.8	12.3	18.4	21.4	16.9	5.3	1.6	0.4	0.1	0.0		
		Deep					0.1	0.4	2.0	11.6	18.2	21.1	16.6	4.2	0.8	0.2	0.0			
	Tech B	25 m/s				0.1	1.4	4.8	9.8	16.9	22.5	26.1	21.8	9.0	2.9	0.9	0.2	0.1		
		Moderate			0.0	0.0	0.2	1.9	4.4	11.6	18.7	24.0	18.6	6.2	1.7	0.6	0.1	0.0		
		Deep					0.1	0.4	2.2	10.5	18.2	23.6	17.9	5.0	1.2	0.4	0.1			

Days with maximum fleet-level wind speed above 20 m/s cover approximately 8 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

Appendix K: Latest forecast errors for days with maximum wind speed below 20 m/s

“Last” forecast errors: average number of days per year with at least one event when the daily max fleet-level wind speed is below 20 m/s.

			Negative forecast error (GW)									Positive forecast error (GW)								
			4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
Existing (2.3 GW)								0.0	1.6	75.1	217.2	246.9	115.5	3.2	0.1					
3.0 GW	Tech A	25 m/s						0.2	4.9	117.6	249.9	268.9	165.1	8.6	0.3	0.0				
3.0 GW	Tech A	Moderate						0.2	4.9	117.5	249.8	268.9	165.1	8.6	0.3	0.0				
3.0 GW	Tech A	Deep						0.2	4.9	117.5	249.8	268.9	165.1	8.6	0.3	0.0				
3.0 GW	Tech B	25 m/s					0.0	0.2	4.6	107.8	243.9	275.1	173.5	8.6	0.4	0.0				
3.0 GW	Tech B	Moderate					0.0	0.2	4.6	107.6	243.9	275.1	173.5	8.6	0.4	0.0				
3.0 GW	Tech B	Deep					0.0	0.2	4.6	107.6	243.8	275.1	173.5	8.6	0.4	0.0				
4.0 GW	Tech A	25 m/s				0.0	0.1	0.8	14.0	168.9	275.1	287.1	209.9	23.2	1.3	0.1	0.0			
4.0 GW	Tech A	Moderate					0.1	0.8	14.0	168.6	275.1	287.1	209.8	23.1	1.3	0.1	0.0			
4.0 GW	Tech A	Deep					0.1	0.8	14.0	168.7	275.1	287.1	209.8	23.1	1.3	0.1	0.0			
4.0 GW	Tech B	25 m/s				0.0	0.1	0.8	11.1	146.4	265.3	295.7	231.6	29.5	1.4	0.1	0.0	0.0		
4.0 GW	Tech B	Moderate					0.1	0.8	11.1	146.2	265.2	295.7	231.6	29.4	1.4	0.1	0.0	0.0		
4.0 GW	Tech B	Deep					0.1	0.8	11.1	146.1	265.2	295.7	231.6	29.4	1.4	0.1	0.0	0.0		
4.4 GW	Tech A	25 m/s			0.0	0.0	0.2	1.9	22.4	196.3	285.0	294.3	229.5	37.8	2.8	0.2	0.1	0.0		
4.4 GW	Tech A	Moderate					0.2	1.9	22.4	196.1	284.9	294.3	229.5	37.8	2.8	0.2	0.1	0.0		
4.4 GW	Tech A	Deep					0.2	1.9	22.4	196.1	284.9	294.3	229.5	37.8	2.8	0.2	0.1	0.0		
4.4 GW	Tech B	25 m/s				0.1	0.2	1.6	18.2	173.0	276.3	301.5	252.1	50.4	3.8	0.3	0.0	0.0		
4.4 GW	Tech B	Moderate				0.1	0.2	1.6	18.1	172.8	276.2	301.5	252.1	50.2	3.8	0.3	0.0	0.0		
4.4 GW	Tech B	Deep				0.1	0.2	1.6	18.1	172.7	276.2	301.5	252.1	50.2	3.8	0.3	0.0	0.0		

Days with maximum fleet-level wind speed below 20 m/s cover approximately 92 % of the simulated days (small differences between the scenarios). “Existing” refers to the 2.3 GW of installations.

Acknowledgements
The Elia staff Philippe Magnant, Kristof De Vos and Giovanni Ninite are acknowledged for problem formulation in the request for proposal and for many fruitful meetings, in person as well as on Skype.

Researcher Kaushik Das is acknowledged for the initial discussions and initial coding for the analysis of historical data for BRPs and system imbalances.

DTU Wind Energy is a department of the Technical University of Denmark with a unique integration of research, education, innovation and public/private sector consulting in the field of wind energy. Our activities develop new opportunities and technology for the global and Danish exploitation of wind energy. Research focuses on key technical-scientific fields, which are central for the development, innovation and use of wind energy and provides the basis for advanced education at the education.

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Annex B: historical ramping and storm events

1. Introduction

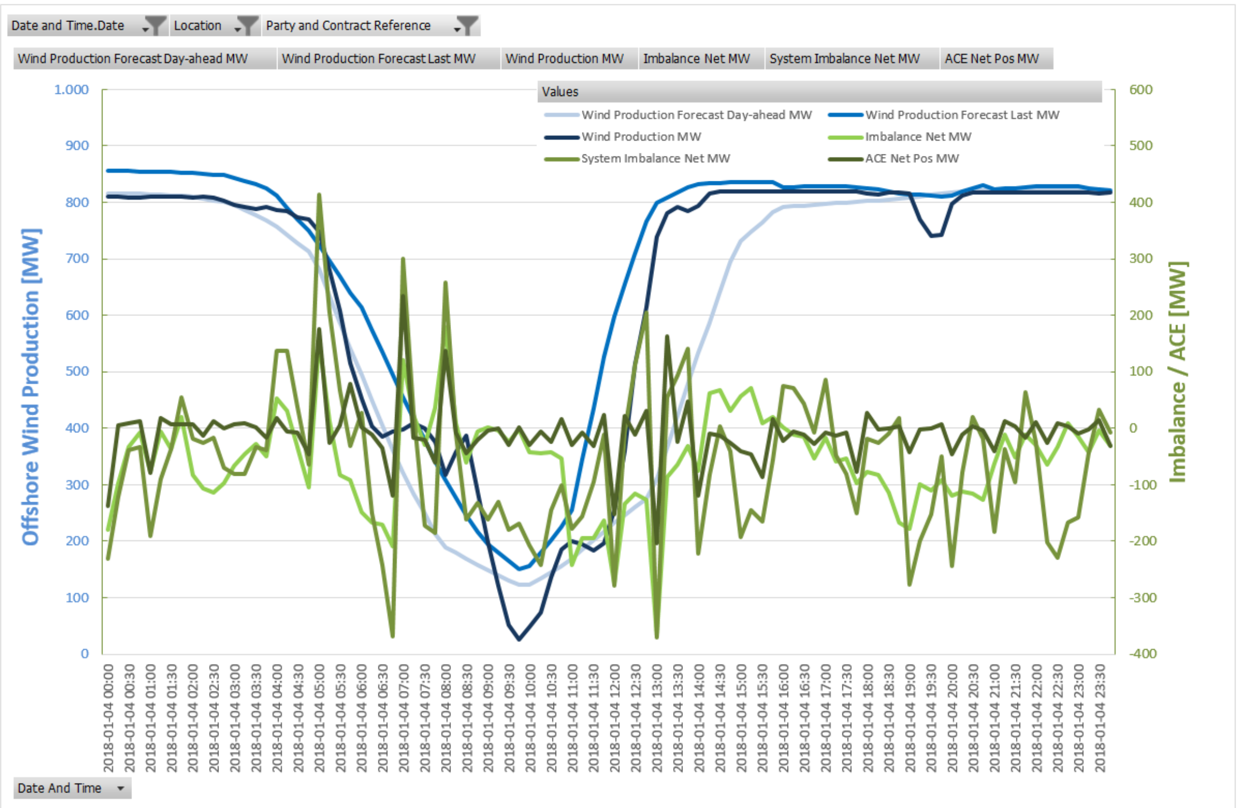
As a basis to define the scenarios of BRPs ability to cover imbalances during extreme events, a case-by-case analysis was performed on the most relevant historical storm and ramping events. This annex provides the graphs of the 20 ramping events and the 6 storm events that have been considered in this exercise.

For each graph:

- The blue curves indicate forecasts and power production. The scale used is on the left axis
- The green curves indicate the imbalances and the ACE value. The scale is on the right axis.
- The “imbalance net” curve corresponds to the sum of the imbalances of the BRPs having at least one offshore wind park in their portfolio, while the “system imbalance” curve represents the total system imbalance.

2. Ramping events

04/01/2018



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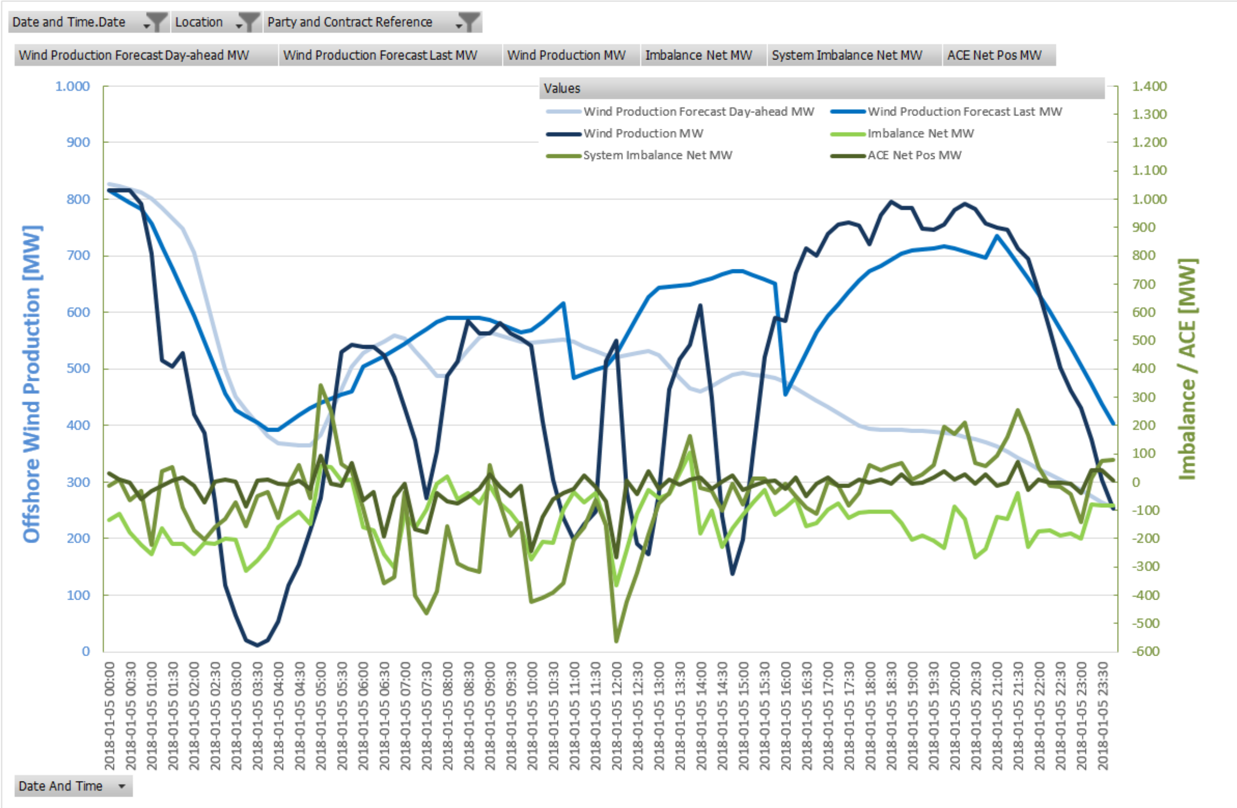

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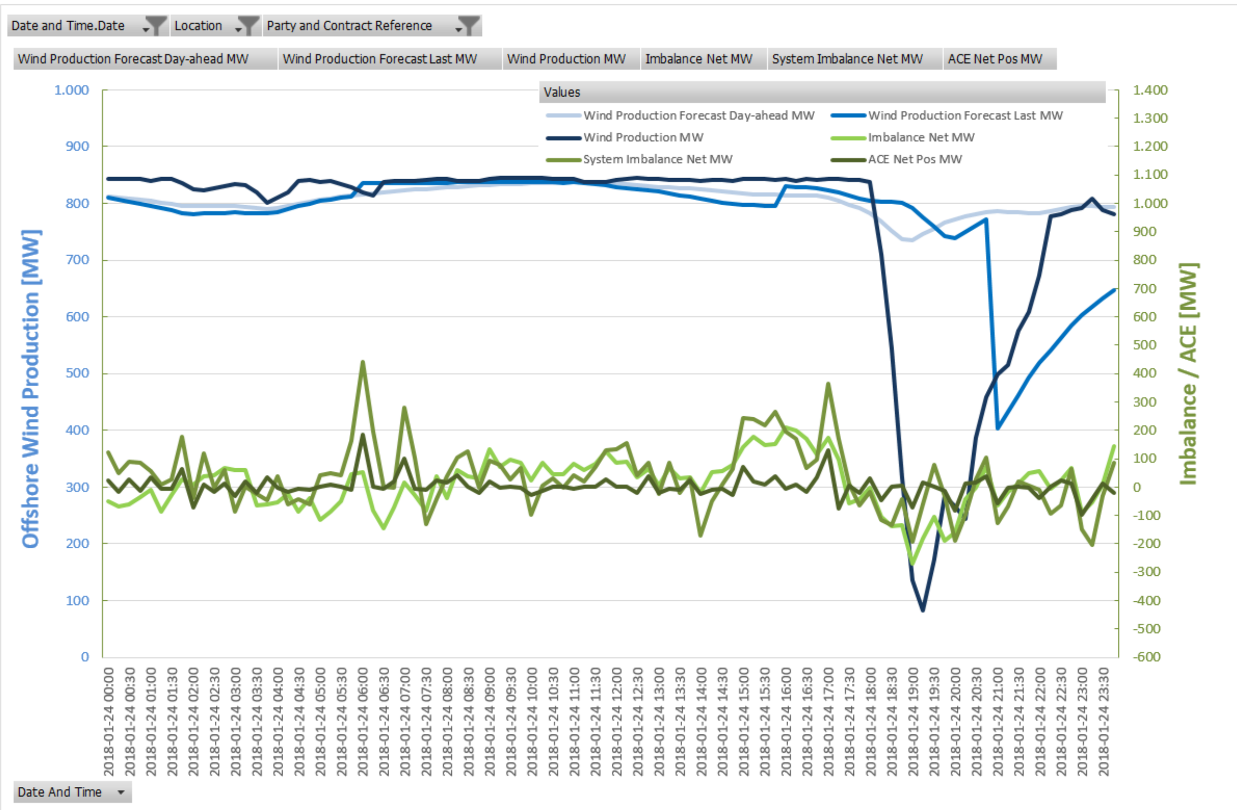

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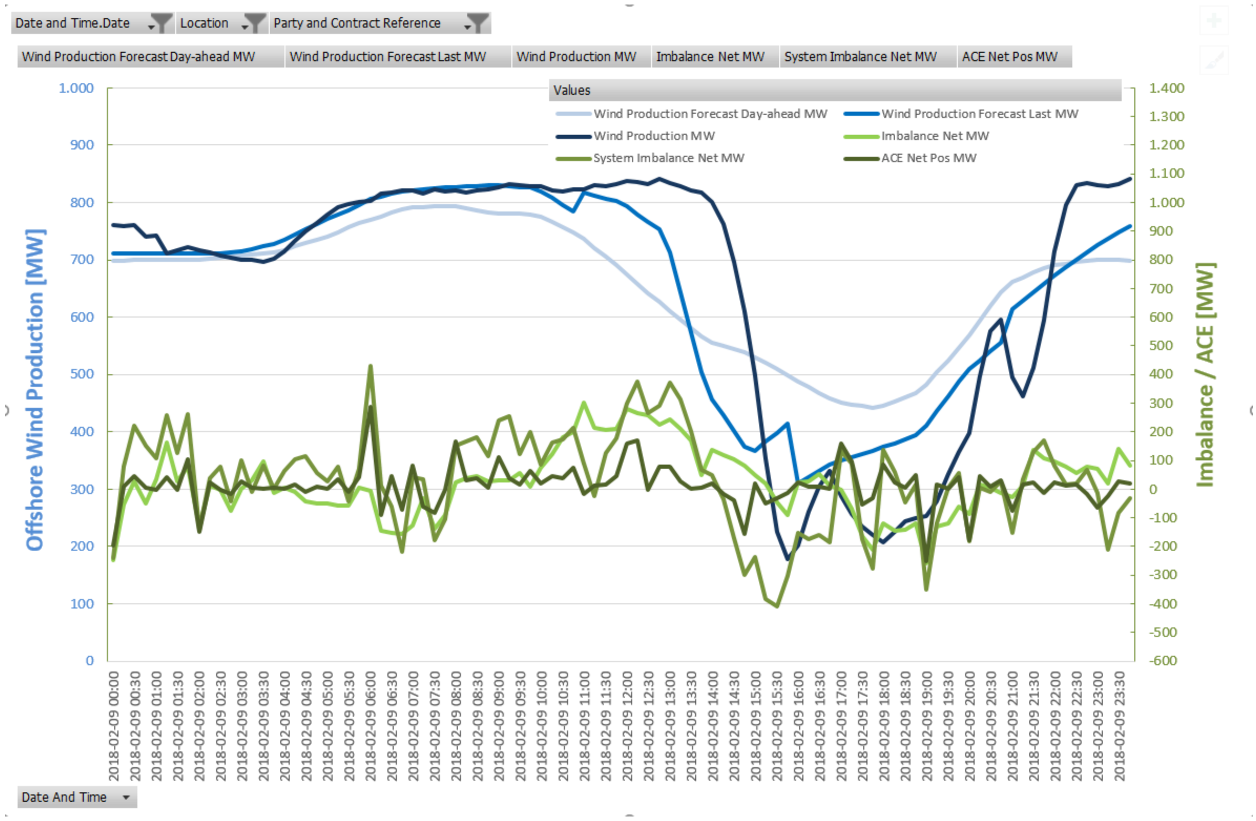

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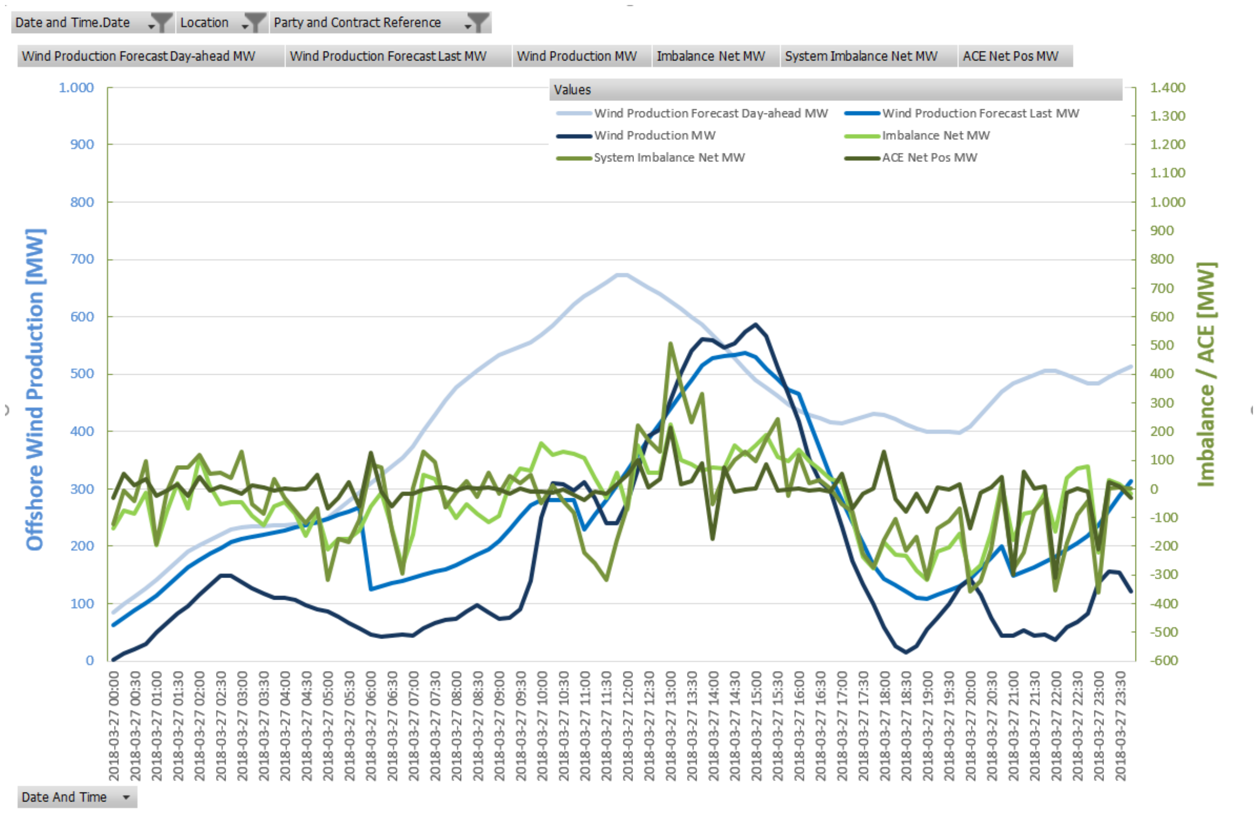

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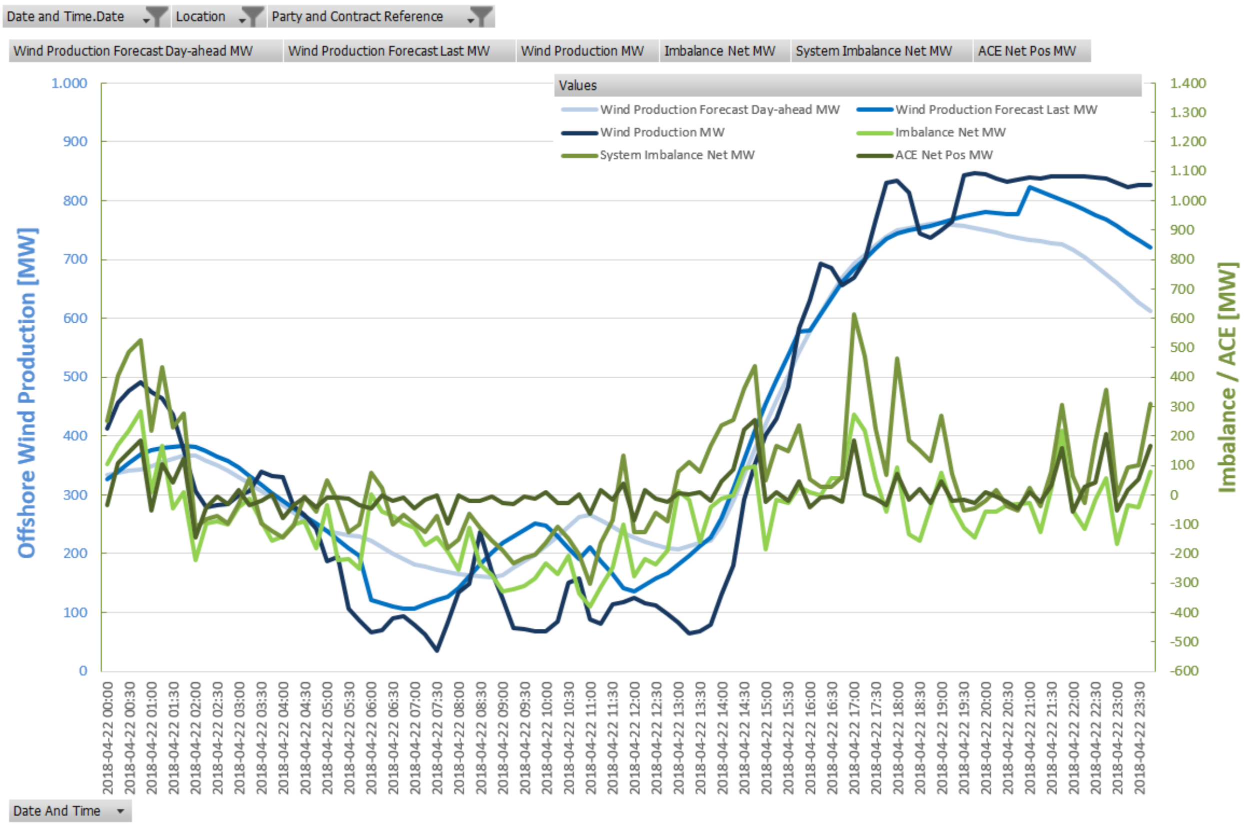

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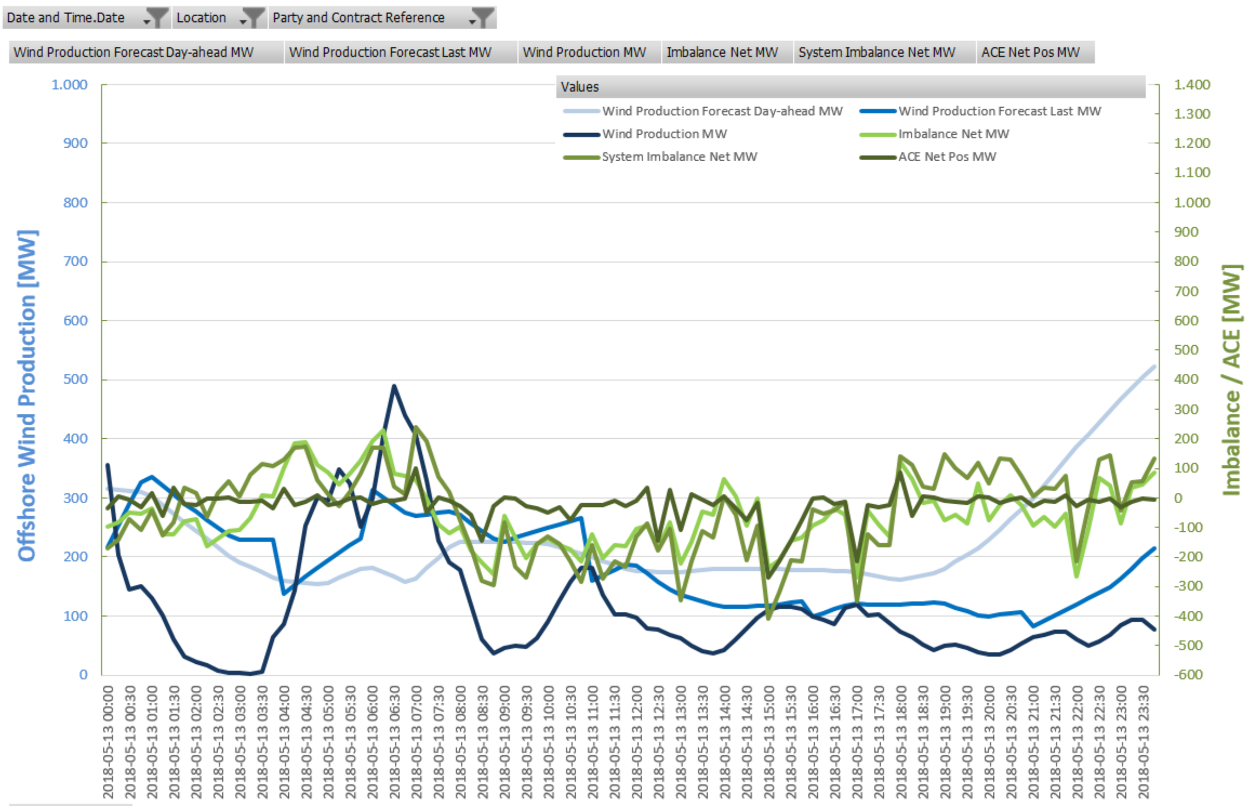

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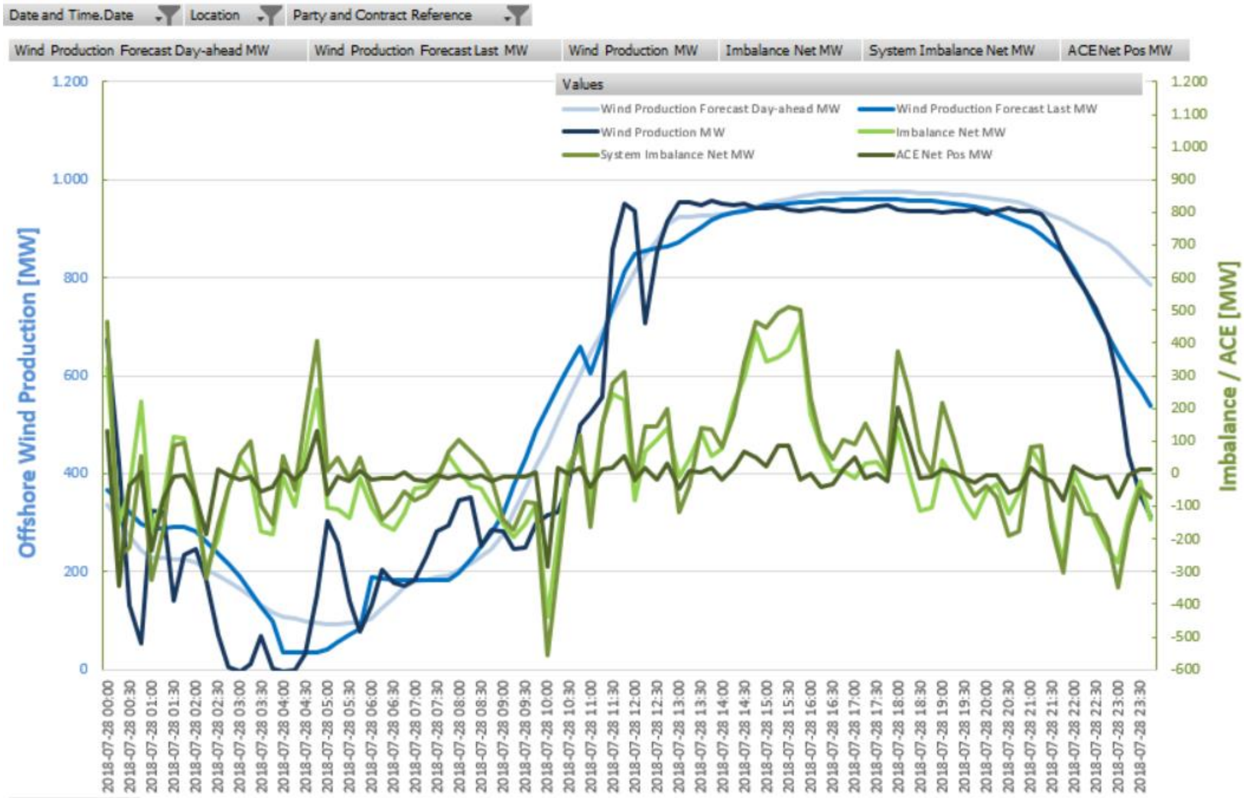

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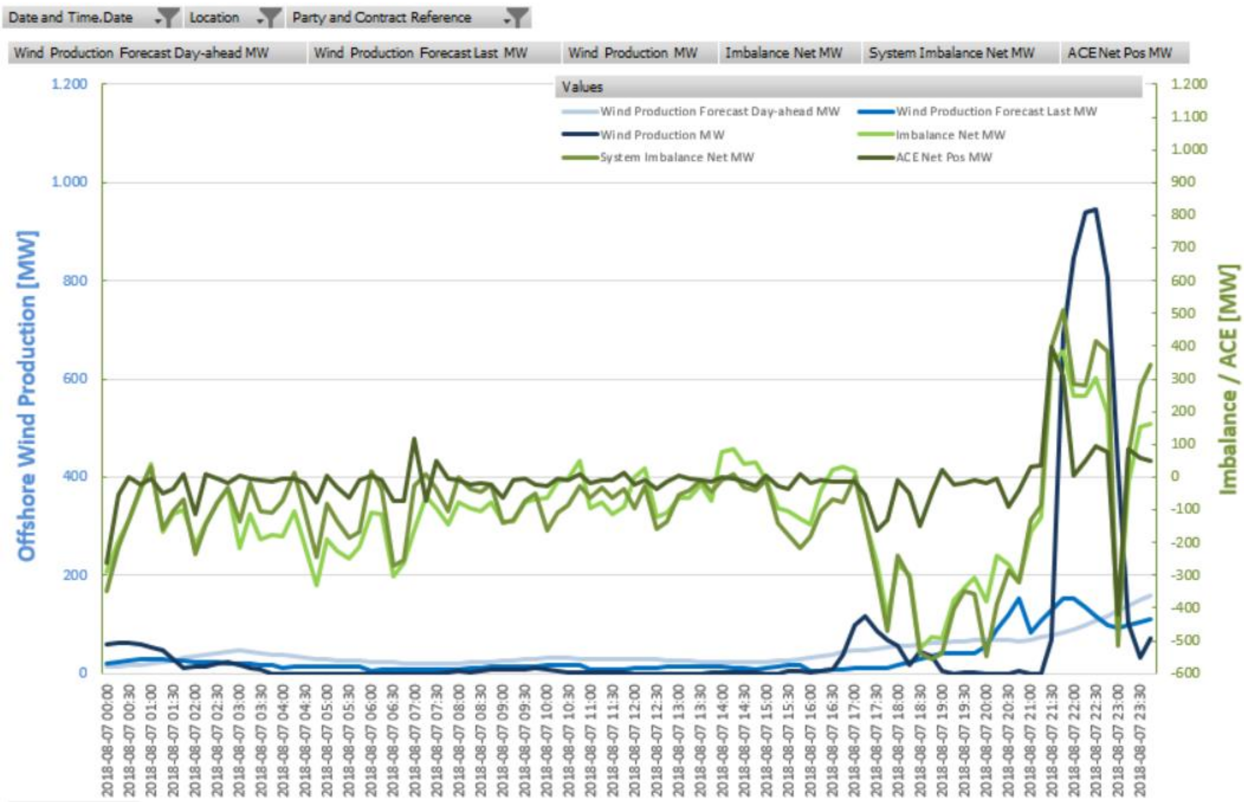

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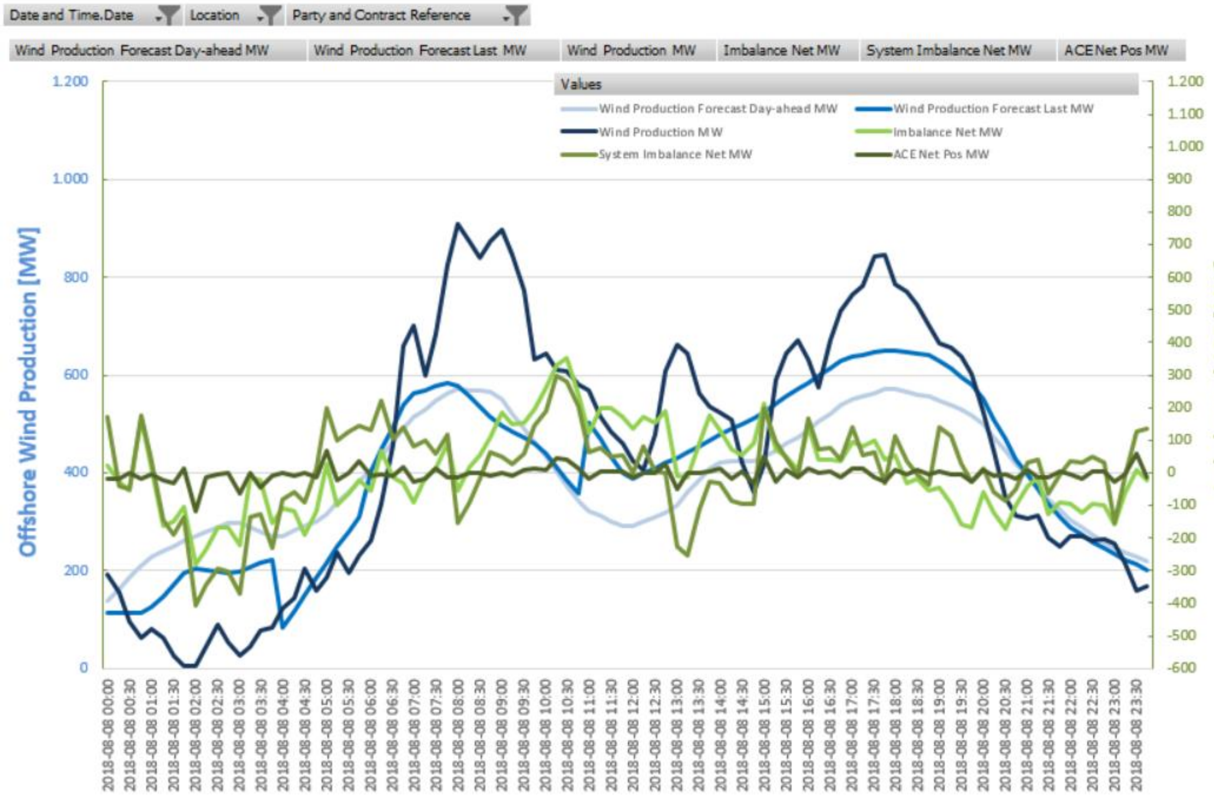

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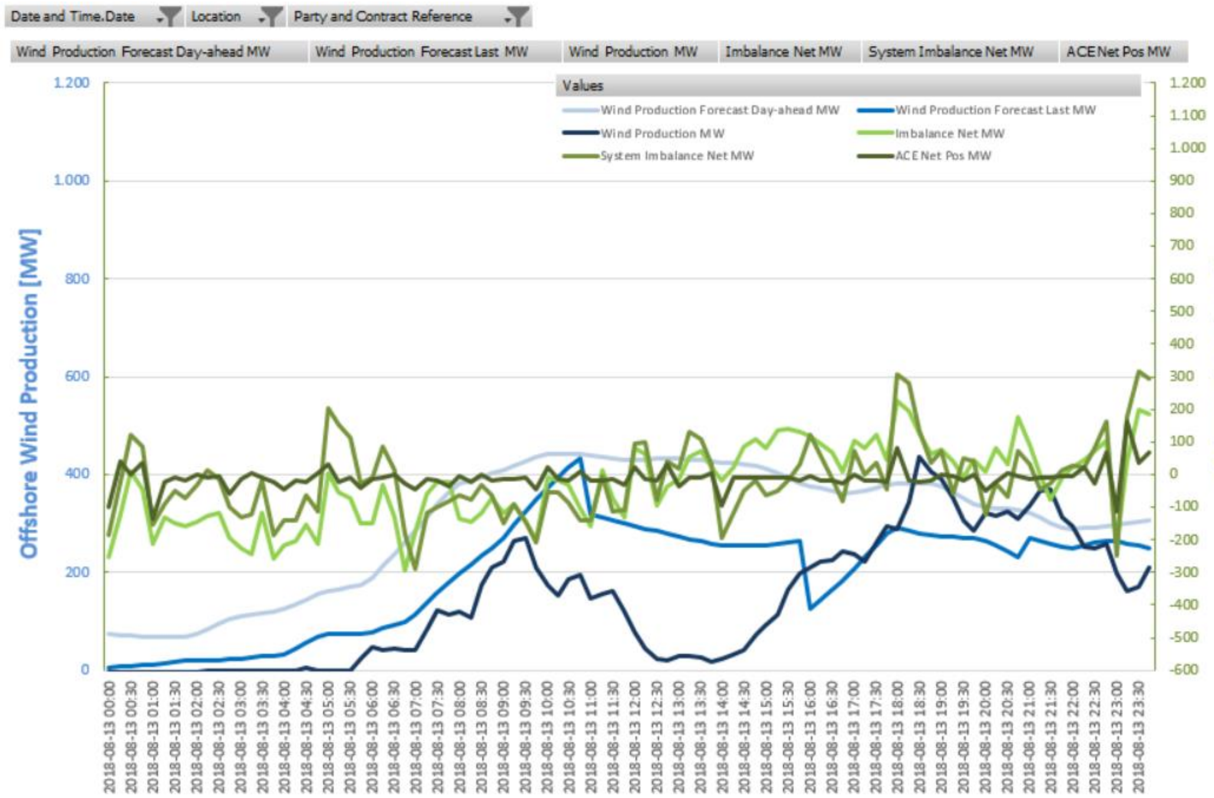

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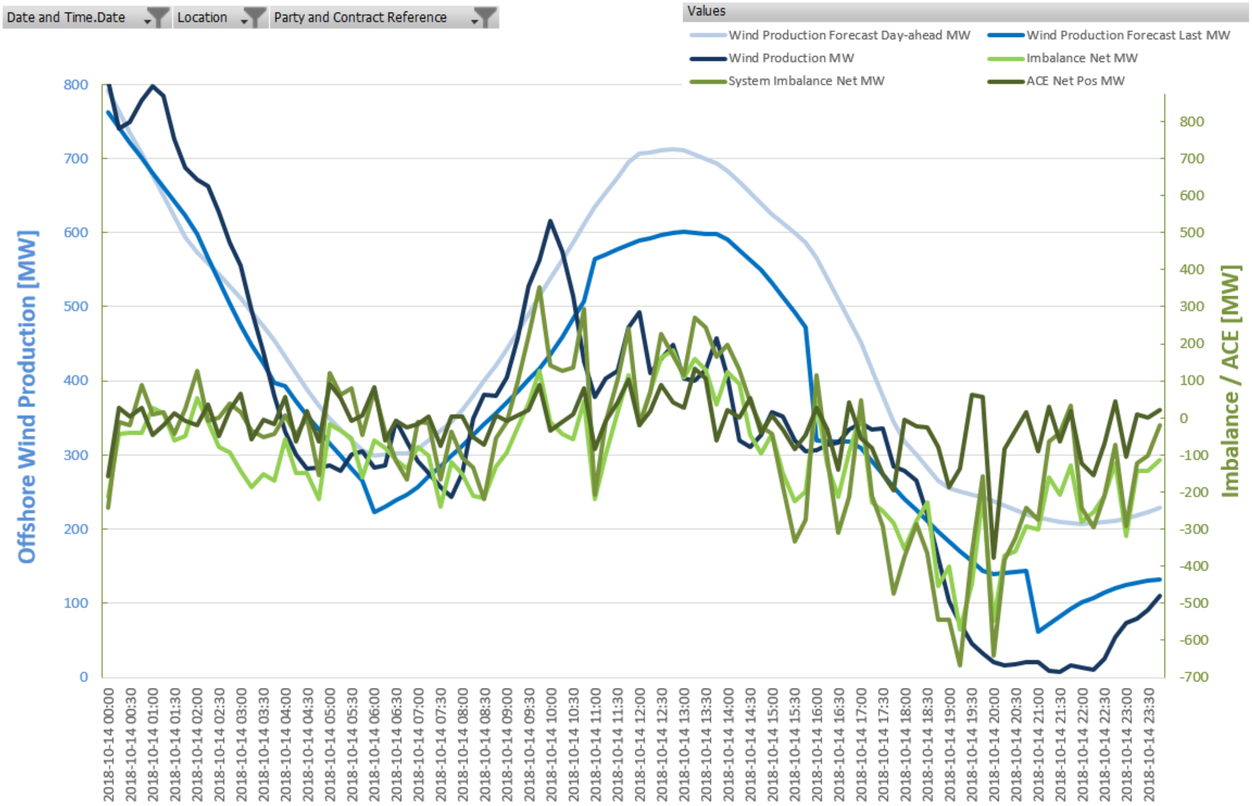

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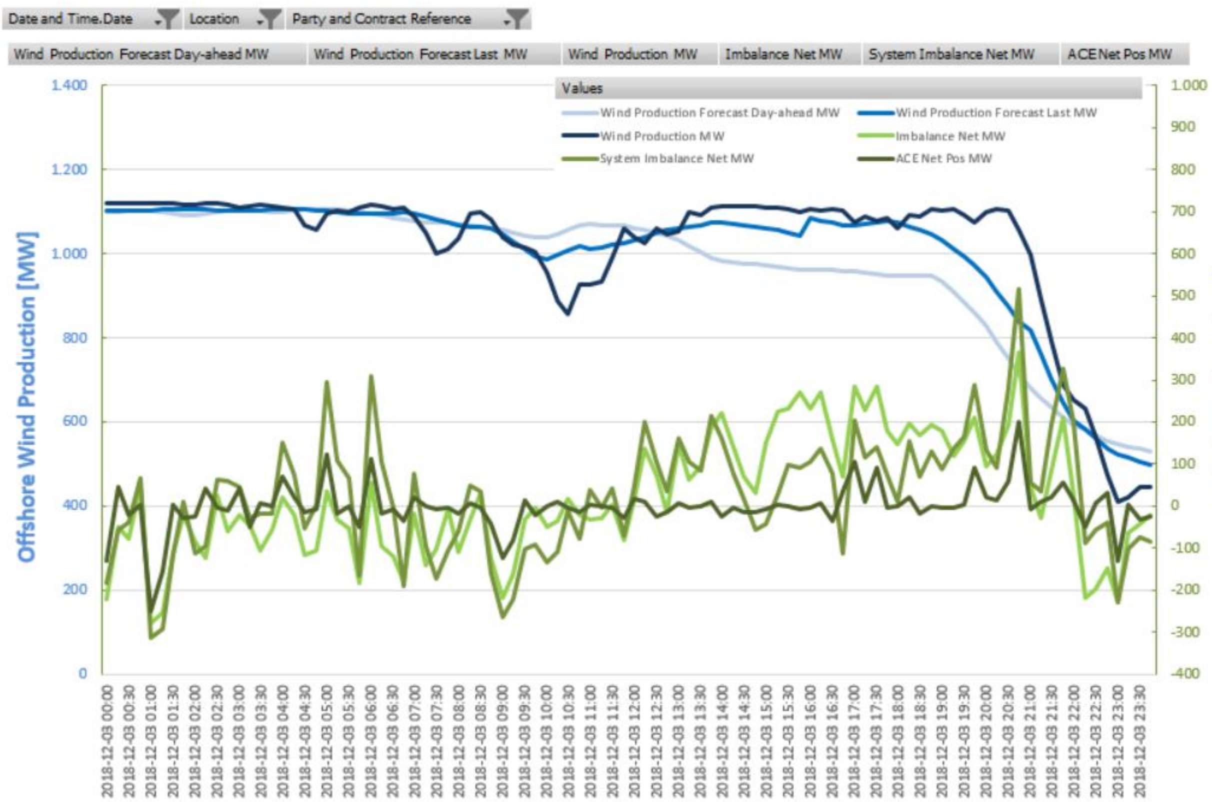

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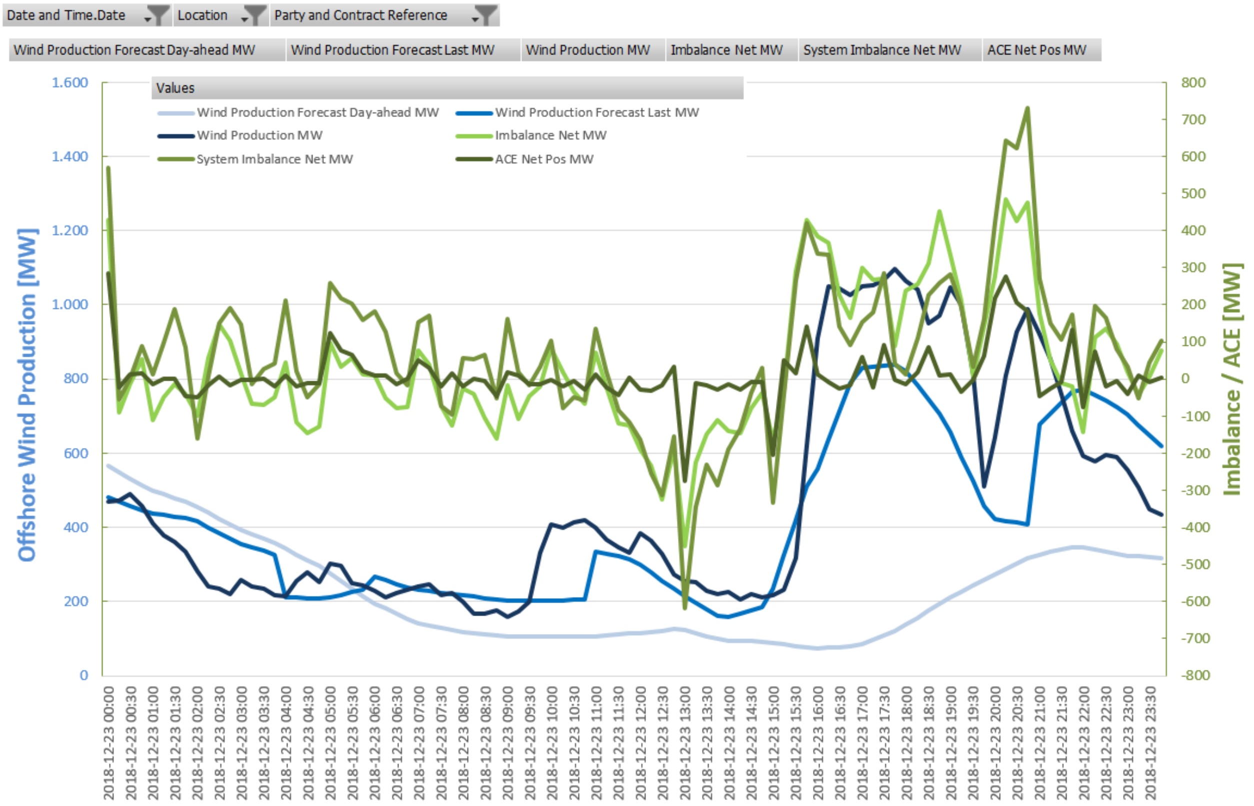

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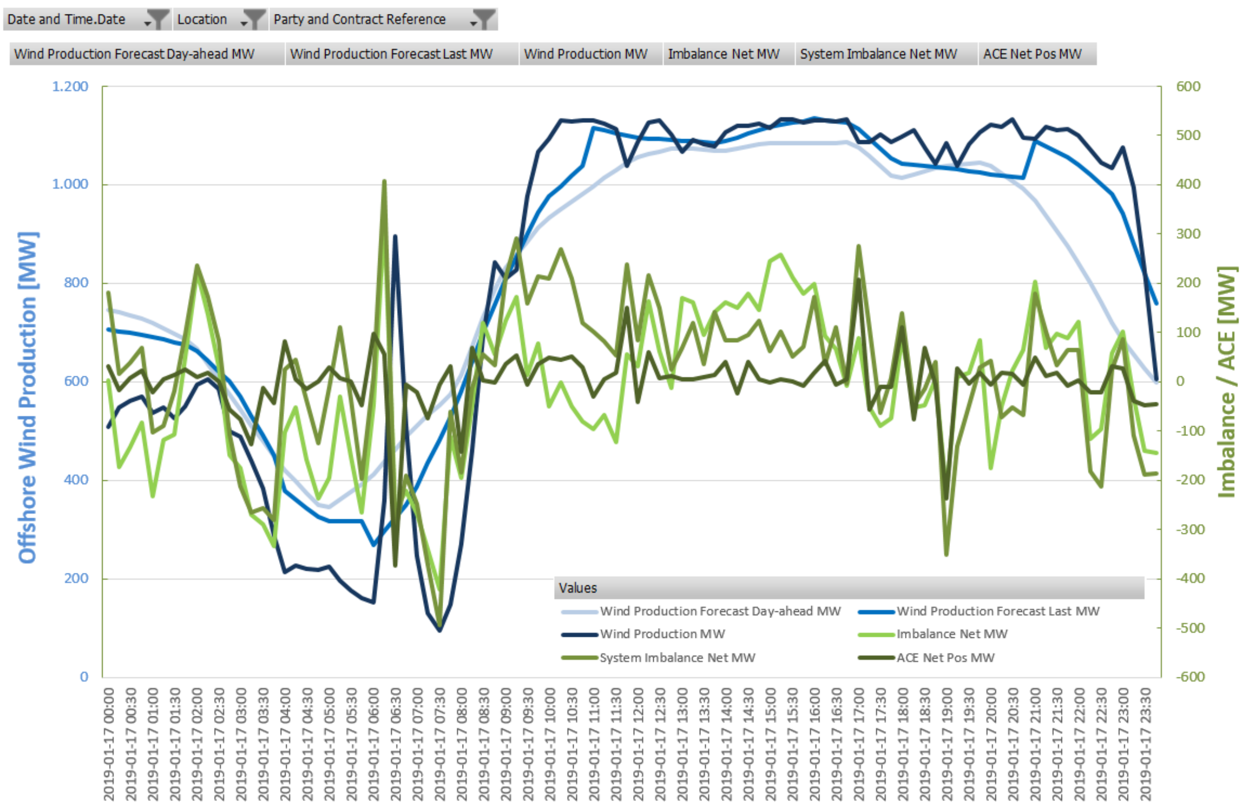

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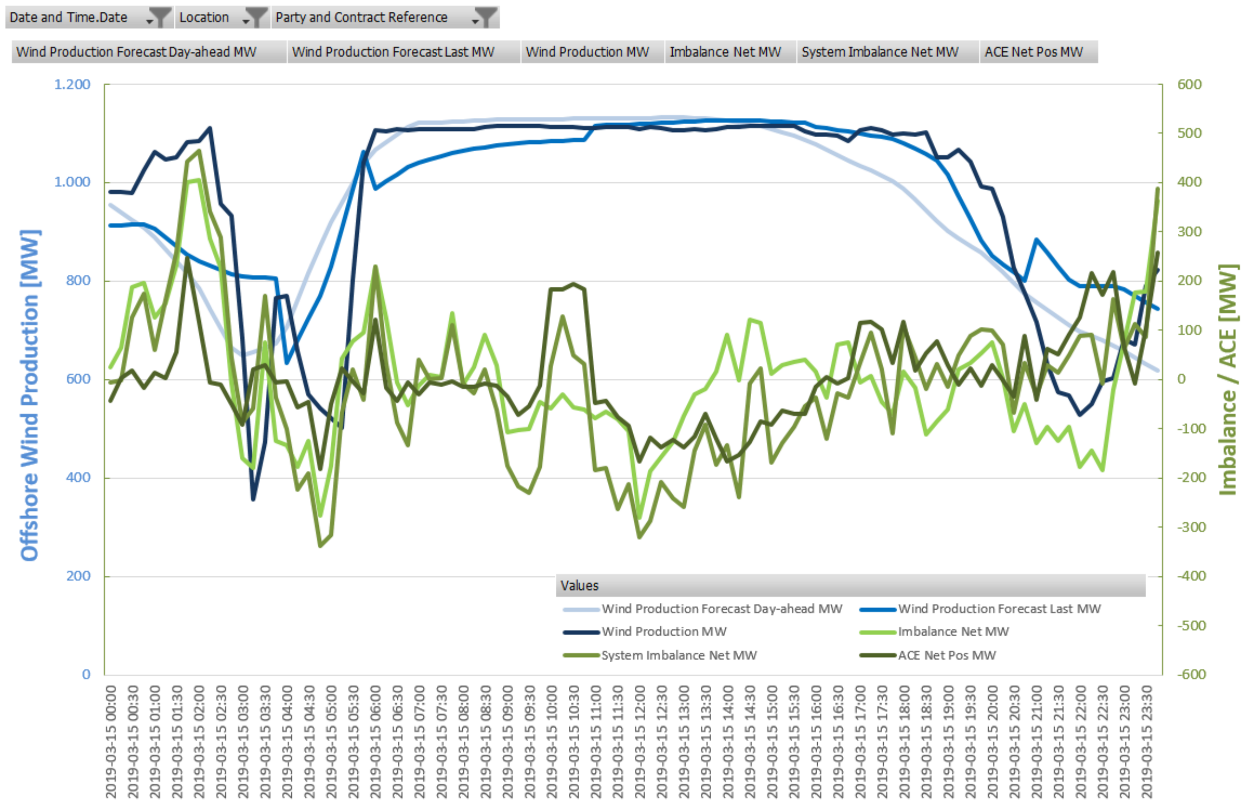

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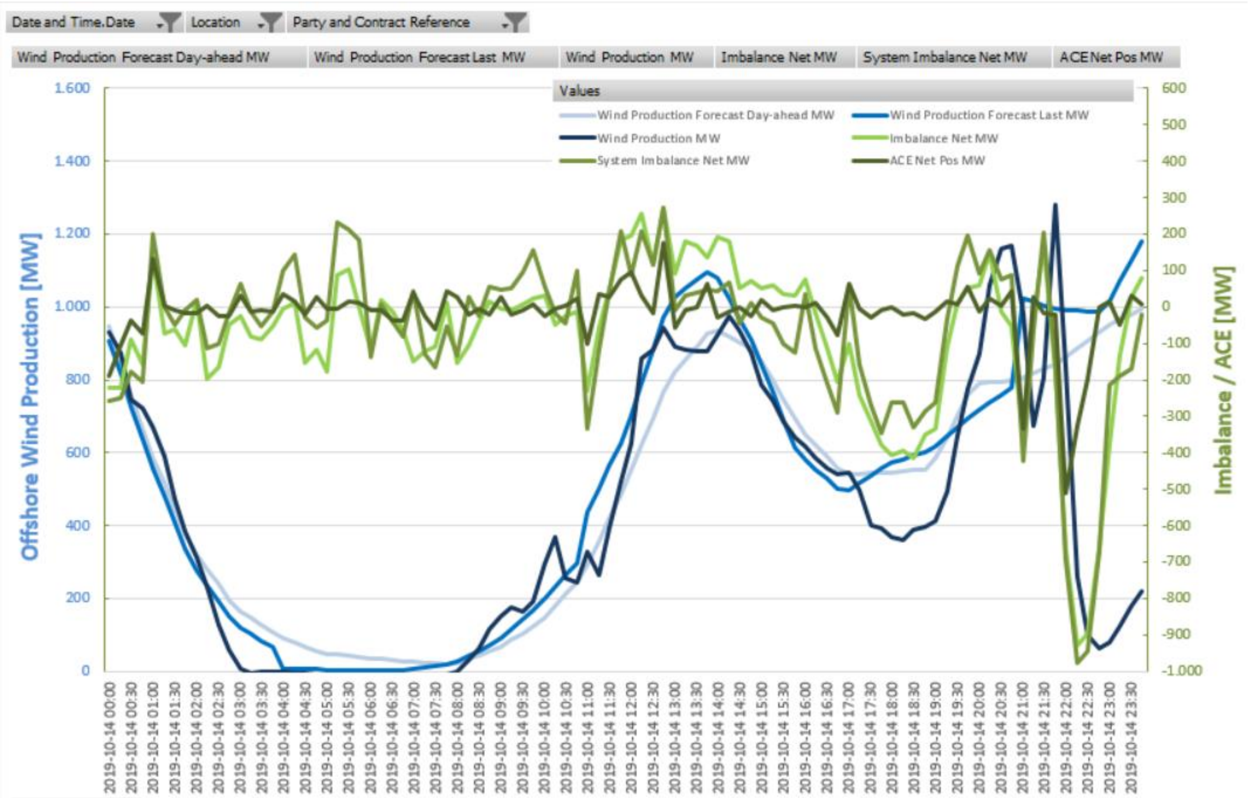

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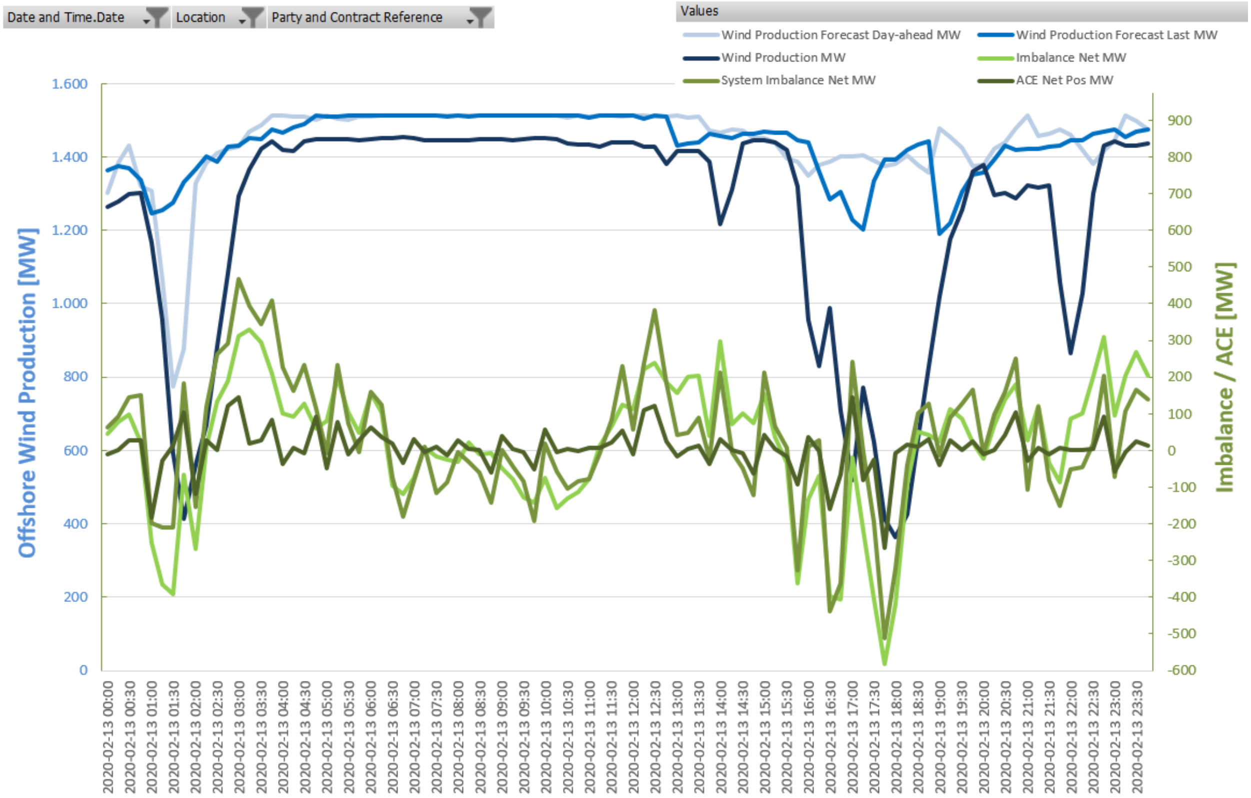

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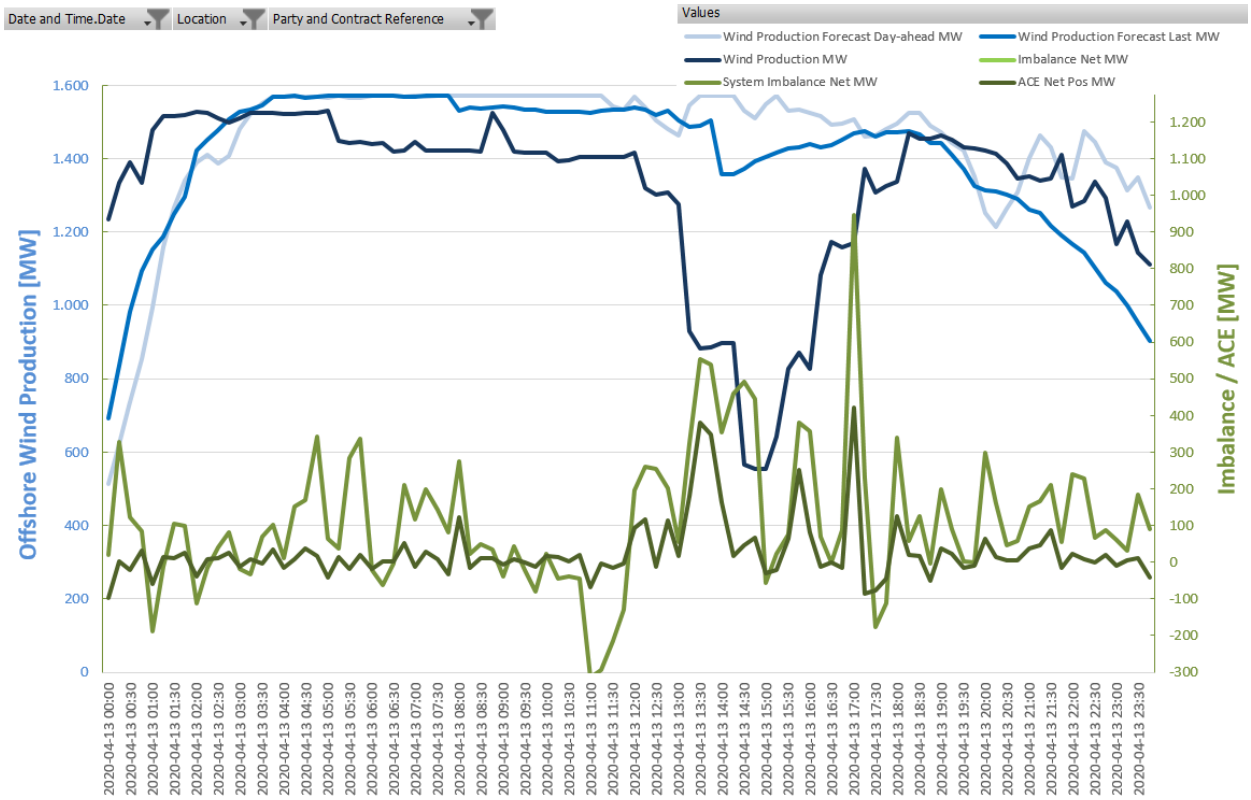

3. Storm events

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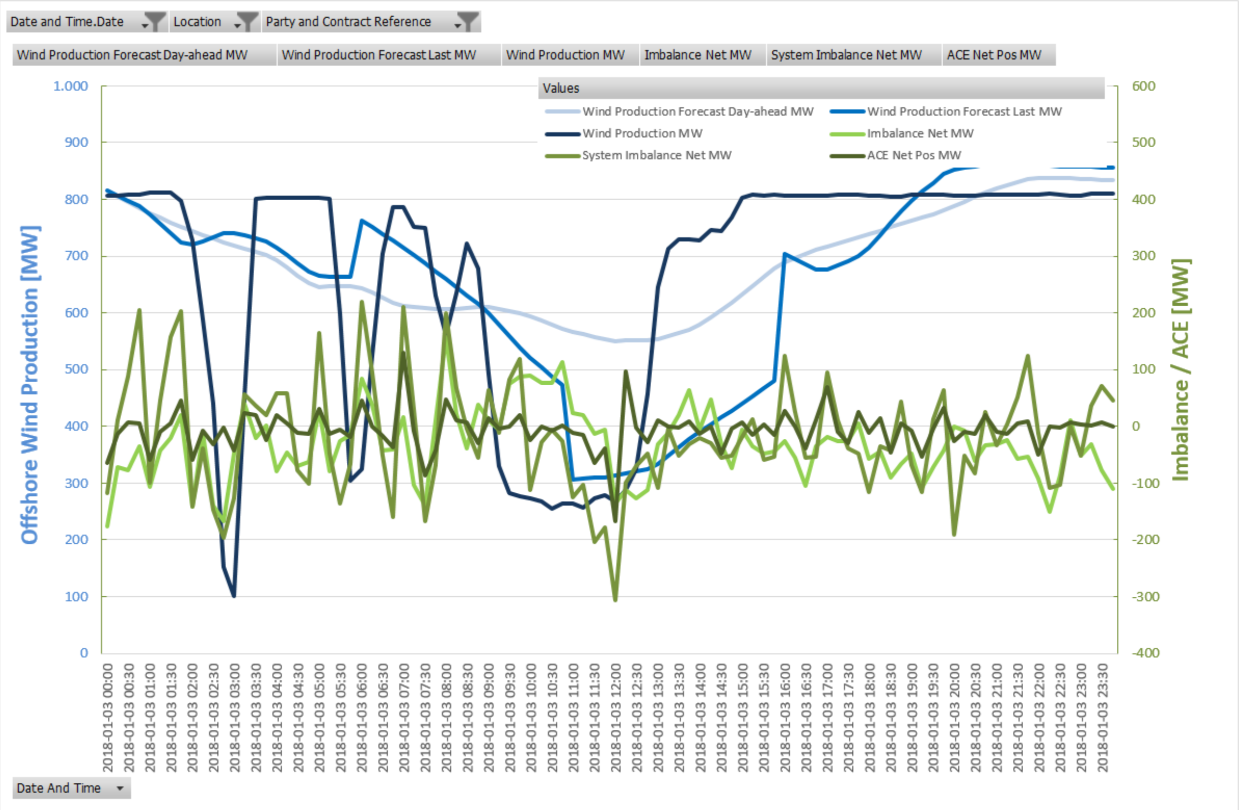

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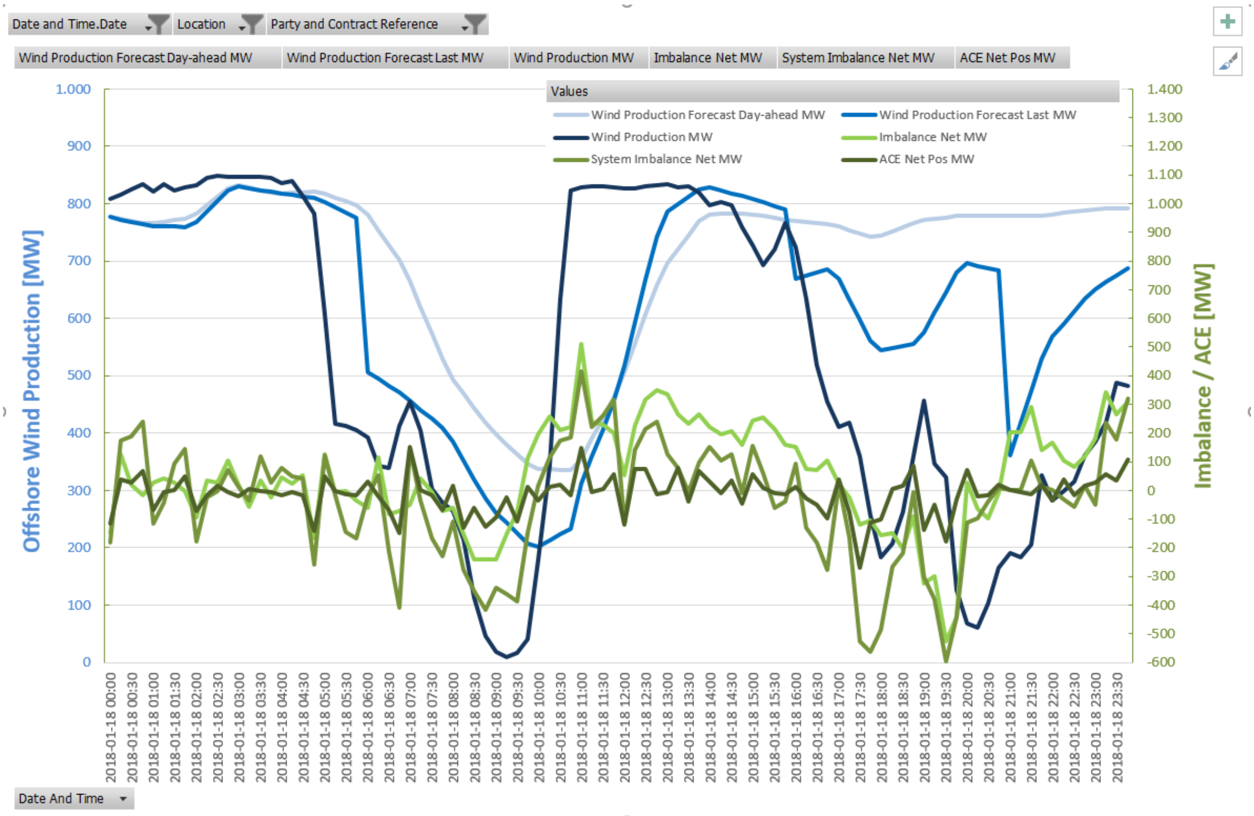

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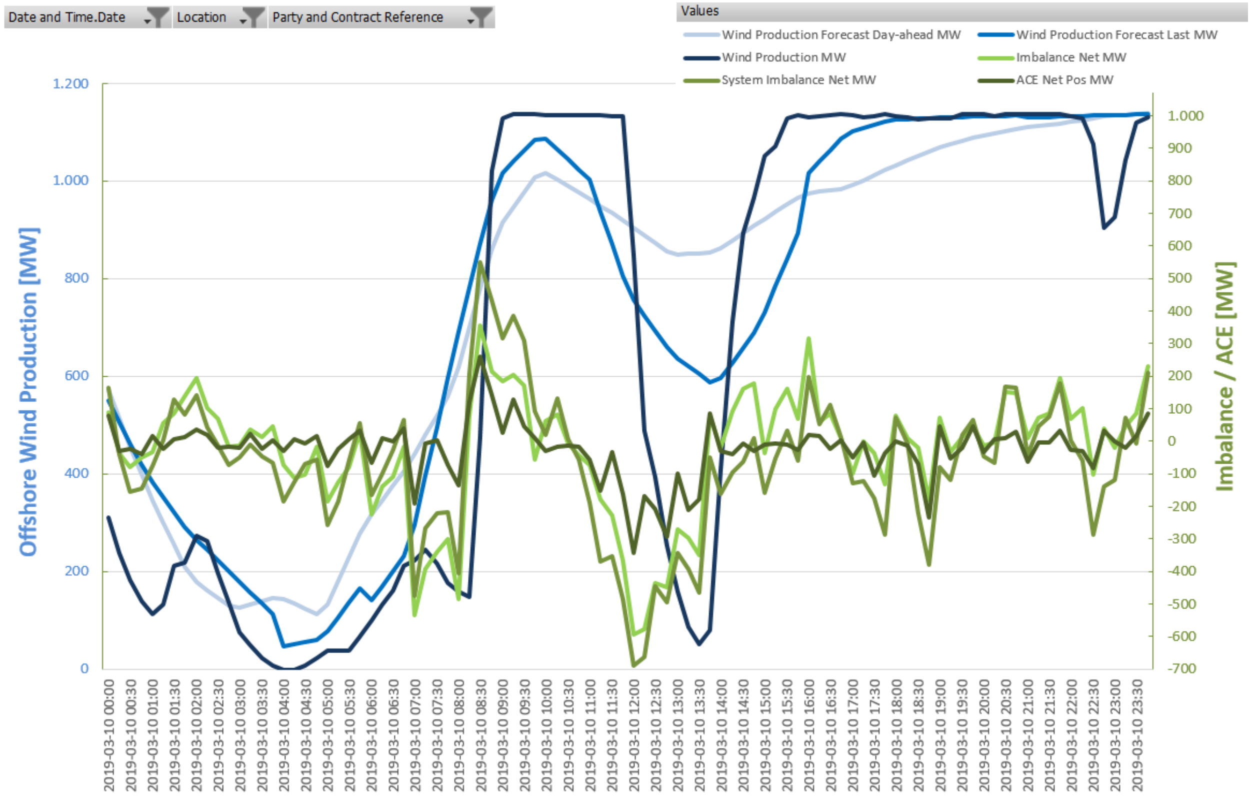

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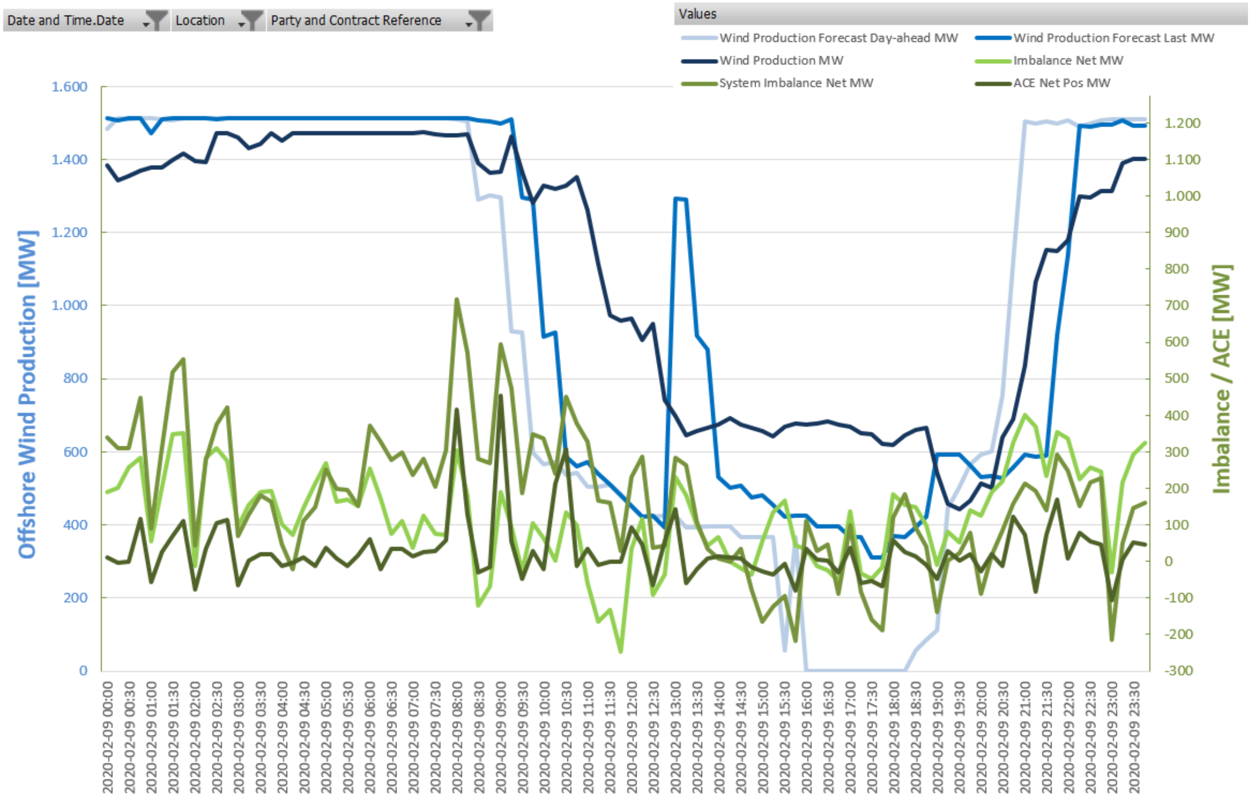

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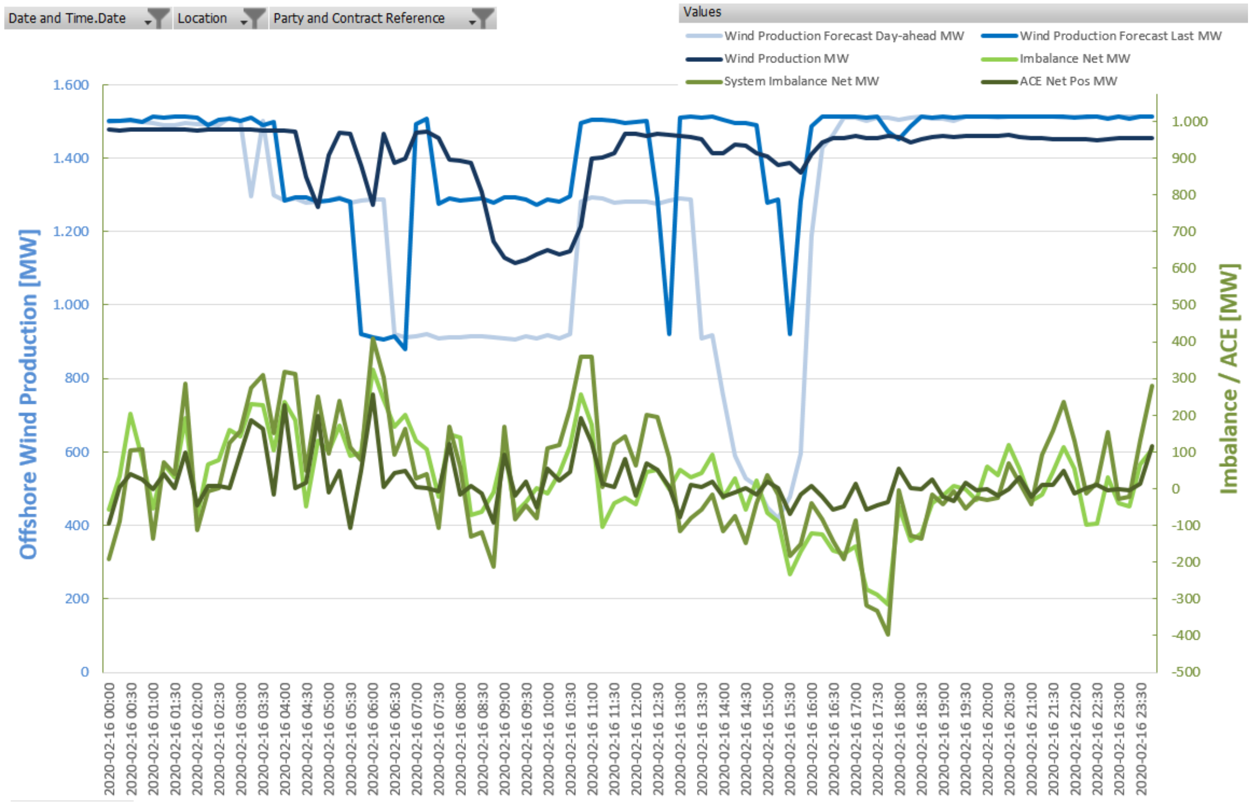
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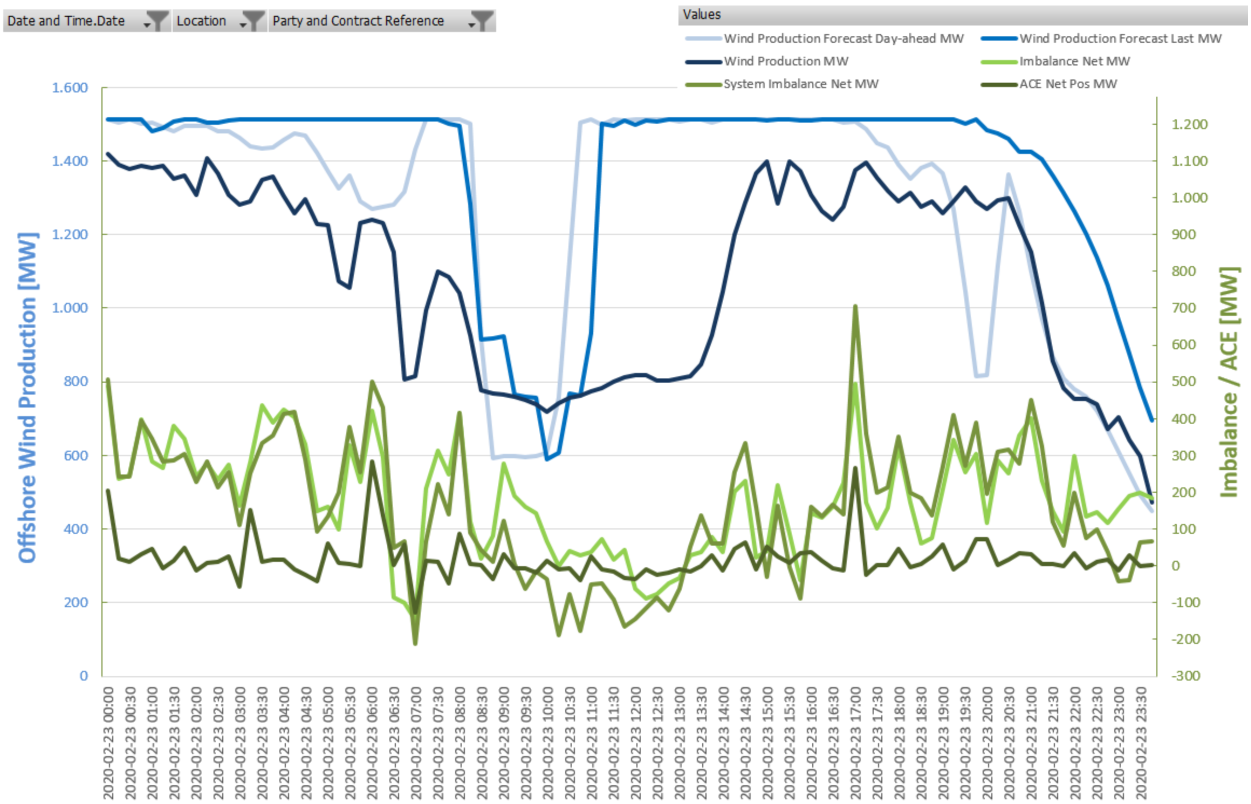
Wind Production Forecast Last MW
Wind Production MW
Imbalance Net MW
System Imbalance Net MW
ACE Net Pos MW
Offshore Wind Production [MW]
Imbalance / ACE [MW]

23/02/2020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Imbalance Net MW
System Imbalance Net MW
ACE Net Pos MW
Offshore Wind Production [MW]
Imbalance / ACE [MW]

Annex C: detailed results of the analysis on real-time system operations

Table of content

1. Introduction

This annex includes all detailed results and corresponding analyses of the simulations performed.

The 2nd wave of offshore wind generation is divided into two phases, namely an increase to maximum 3.0 GW offshore wind generation in the first phase and to a maximum of 4.4 GW in the 2nd phase. As the ramping and storm events may have a different impact for each phase, separate analyses were performed.
The results of the analysis for each event are always compared to the pre-defined validation criteria to determine if the respective type of event can be considered as acceptable without any mitigation measure or restriction.

The structure of the results is the following

- Installed capacity of 3.0 GW
    - Ramping events
        - Upward ramping events with scheduled activations of mFRR means
        - Downard ramping events with scheduled activations of mFRR means
        - Upward ramping events, combination of scheduled and direct activation of mFRR means
        - Downard ramping events, combination of scheduled and direct activation of mFRR means
    - Storm events
        - Scheduled activations of mFRR means
        - Combination of scheduled and direct activation of mFRR means
- Installed capacity of 4.4 GW: same structure.

In each section, the results are shown for all selected events with the sensitivities on the BRP Scenario (Best or Worst Case) and on the FRR contracted volume.

2. Offshore installed capacity of 3.0 GW

2.1 Extreme ramping events

The analysis on extreme ramping events focused on those occurring in 60 minutes time. For each event, a total of 8 simulations have been performed, taking into account the defined scenarios for BRP reaction and balancing energy. The reference case contains an activation of balancing energy by means of scheduled activation, with exception of aFRR balancing capacity which is activated by the LFC controller.

The resulting Area Control Error (ACE) is compared to the different thresholds used as validation criteria (see par-Section 5.2.2 of the main report) for which the continuous duration above each threshold is monitored. The threshold, together with the continuous duration, defines whether an event in combination with the selected scenario of BRP reaction and balancing energy can be accepted or not.

The results are shown in the following tables by means of a color indication as explained in paragraph 5.2.2 validation criteria of the main report. There are violations if one or many thresholds are exceeded.
As a reminder, the thresholds used are:
- Threshold 1 (T1) = 375 MW
- Threshold 2 (T2) = 750 MW
- Threshold 3 (T3) = 1500 MW

2.1.1 Upward direction using scheduled activation of mFRR means

Scenario 3,0 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
_Deep_2p5GW_	Worst Scenario	1104	375	56	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	1500	375	36	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2000	375	36	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2500	375	36	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1104	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2500	375	0	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1104	375	16	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1500	375	16	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2000	375	16	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2500	375	16	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1104	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1104	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1104	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2500	375	0	750	0	1500	0

Table 1 Results for simulated ramping events in the upward direction in 60 minutes for 3.0 GW offshore generation

Table 1 shows the results related to ramping events in the upward direction which occur within a period of 1 hour. All cases can be considered as acceptable, except for the highest observed ramping event of 2.5 GW which is not acceptable for the worst case scenario of BRP reaction. The latter exceeds the 15-minute duration (36 minutes) for threshold 1 for higher values of FRR, however for the minimum value of FRR means a large deviation of the continuous duration is observed (56 minutes).

The 2.0 GW event for the worst case BRP scenario exceeds the 15-minute duration for threshold 1 by one minute, for which it turns orange.

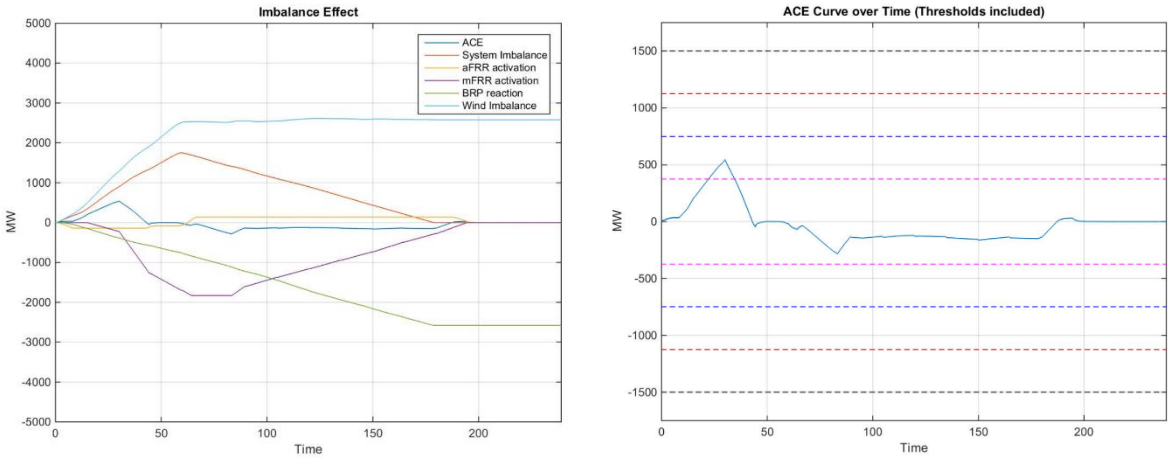

Figure 1 – Plots visualizing the simulated data (left) and Area Control Error compared to the thresholds used for validation (right) for a ramping event of 2.5 GW in the upward direction in 1 hour for BRP worst case with 2000 MW of FRR

The left plot represented by Figure 1 displays the BRP reaction and activation of aFRR and mFRR means during the course of the simulation to compensate for the deviation of offshore generation under the form a 2.5 GW ramping event in the upward direction which occurs within one hour. The vertical axis represents the power values in MW, while the horizontal axis displays the time in minutes. The same axes are used by the plot on the right which contains a detailed plot for the Area Control Error with an indication of the thresholds used for validation of the event.

The System Imbalance achieves its maximum value at the end of the ramping event, as the BRP only covers 30% of the power deviation during the ramping event, after which a linear increase to 100% coverage after 2 hours occurs. The highest values of System Imbalance are fully compensated by the activation of FRR means, however the peak in Area Control Error does not occur at the moment of highest System Imbalance but during the first 40 minutes of the simulation. This is related to the fact that there is enough FRR in the system to cover the highest observed System Imbalance, however the mFRR activation show a delay in comparison to the system imbalance during the first 40 minutes. This is mainly related to modeled manual activation of mFRR by the operator by use of scheduled activation.

2.1.2 Downward direction using scheduled activation of mFRR means

Scenario 3,0 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
Deep-2p5GW	Worst Scenario	1104	375	69	750	0	1500	0
Deep-2p5GW	Worst Scenario	1500	375	34	750	0	1500	0
Deep-2p5GW	Worst Scenario	2000	375	34	750	0	1500	0
Deep-2p5GW	Worst Scenario	2500	375	34	750	0	1500	0
Deep-2p5GW	Best Scenario	1104	375	6	750	0	1500	0
Deep-2p5GW	Best Scenario	1500	375	6	750	0	1500	0
Deep-2p5GW	Best Scenario	2000	375	6	750	0	1500	0
Deep-2p5GW	Best Scenario	2500	375	6	750	0	1500	0
Deep-2p0GW	Worst Scenario	1104	375	9	750	0	1500	0
Deep-2p0GW	Worst Scenario	1500	375	9	750	0	1500	0
Deep-2p0GW	Worst Scenario	2000	375	9	750	0	1500	0
Deep-2p0GW	Worst Scenario	2500	375	9	750	0	1500	0
Deep-2p0GW	Best Scenario	1104	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1104	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1104	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2500	375	0	750	0	1500	0

Table 2– ***Results for simulated downwards ramping events in 60 minutes for 3.0 GW offshore generation***

Table 2 shows the results related to ramping events in the downward direction which occur within a period of 1 hour. All cases can be considered as acceptable, except for the highest observed ramping event of 2.5 GW which is not acceptable for the worst case scenario of BRP reaction. The latter exceeds the 15-minutes duration (34 minutes) for threshold 1 for higher values of FRR, however for the minimum value of FRR equal to the contracted reserve capacity a large deviation of the continuous duration is observed (69 minutes).

The simulated 2.0 GW event for the worst case BRP scenario doesn't lead to any violation as was the case for the upward scenario. This observation should however be considered with the necessary precaution, as each event was only represented by one specific event. There might occur events of 2.0 GW in the downward direction for which the 15 min ramping event within one hour is slightly higher, leading to again a violation of threshold 1, as was the case for the upward ramping event.

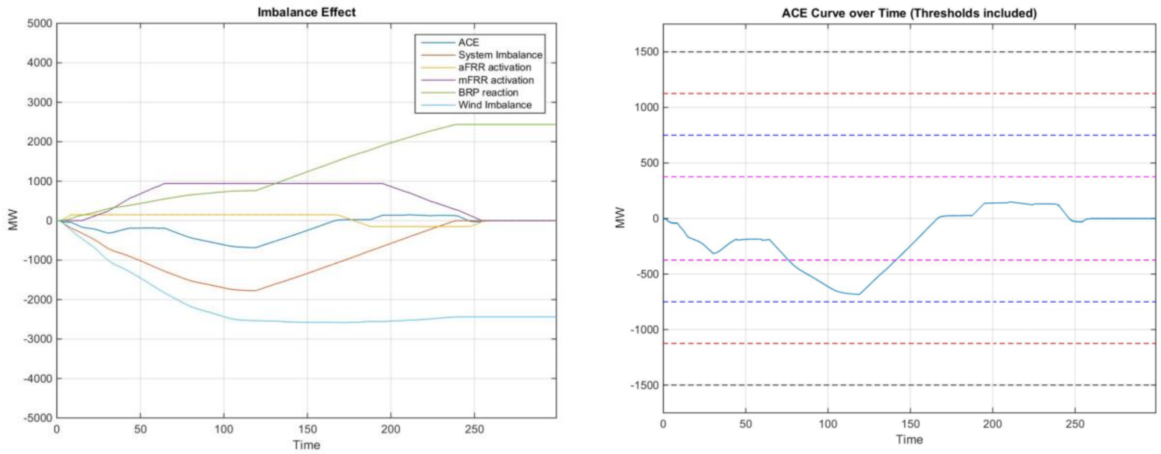

Figure 2– Plots visualizing the simulated data (left) and Area Control Error compared to the thresholds used for validation (right) for a ramping event of 2.5 GW in the downward direction in 1 hour for BRP worst case with 1104 MW of FRR

Figure 2 displays the BRP reaction and activation of aFRR and mFRR means during the course of the simulation to compensate for the deviation of offshore generation under the form of a 2.5 GW ramping event in the downward direction which occurs within one hour. The vertical axis represents the power values in MW, while the horizontal axis displays the time in minutes. The same axes are used by the plot on the right which contains a detailed plot for the Area Control Error with an indication of the thresholds used for validation of the event.

The System Imbalance achieves its maximum value at the end of the ramping event, as the BRP only covers 30% of the power deviation during the ramping event, after which a linear increase to 100% coverage after 2 hours occurs. The highest values of System Imbalance is however not fully compensated by the activation of FRR means, for which the highest peak of Area Control Error occurs at the moment of highest System Imbalance at the end of the ramping event. This is related to the fact that there is not enough FRR in the system to cover the highest observed System Imbalance, which is more significant than the delay in mFRR activation in comparison to the system imbalance. This explains the higher duration in violation of threshold 1 in comparison to the scenario with higher FRR volumes.

2.1.3 Upward direction using a combination of scheduled and direct activation of mFRR means

Scenario 3,0 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
_Deep_2p5GW_	Worst Scenario	1104	375	29	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	1500	375	11	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2000	375	11	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2500	375	11	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1104	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2500	375	7	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1104	375	0	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1500	375	10	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2000	375	20	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2500	375	20	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1104	375	3	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1500	375	14	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2000	375	14	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2500	375	14	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1104	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1104	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2500	375	0	750	0	1500	0

Table 3 – Results for simulated upward ramping events in 60 minutes for 3.0 GW offshore generation

Using a combination of scheduled and direct activation of mFRR means generally leads to less delay in mFRR means. In its turn, this will generally lead to a lower peak of the ACE resulting in no violation of a threshold or a violation for with a shorter duration.

This effect can clearly be observed for the 2.5 GW ramping event in the upward direction, where the violation of threshold 1 is still present for the worst case of BRP reaction but where the duration has significantly change from 36 minutes to an acceptable level of 11 minutes for the higher mFRR volumes. The violation for the scenario with only contracted reserve capacity is still present but the duration is now limited at 29 minutes. The fact that the violation is still present is related to the lower FRR volume which is not capable of covering the highest peak of the system imbalance until the moment the BRP coverage starts increasing towards 100%.

In general all scenario, showed improvement in term of violation durations, some limited increase observed in term of recorded minutes without direct impact on the violation status. Such increase can occur in case of fast change of the ramping gradient direction (2.0 GW the decrease) where a direct activation on top of the scheduled one would result in an over-compensation, as observed in the below figure, such behavior can be also observed in reality if the subsequent level of imbalance is over-estimated.

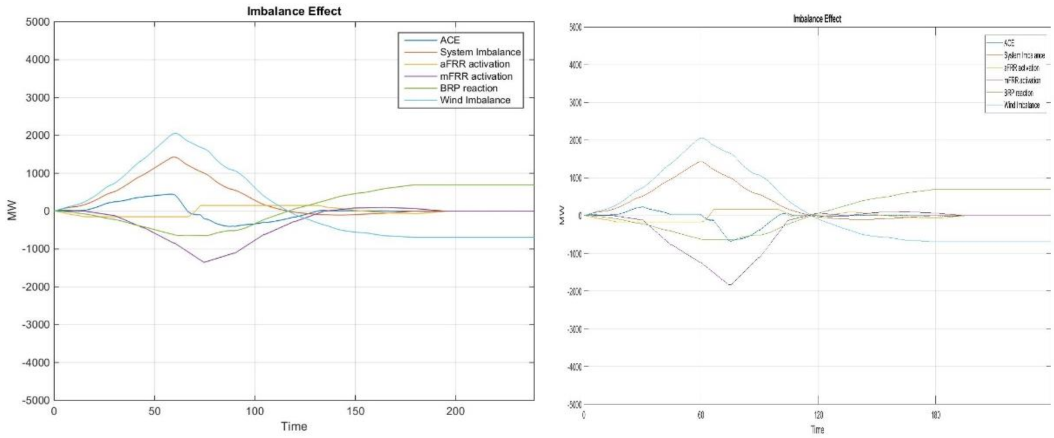

Figure 3 – Plots visualizing the simulated data using the default model (left) and simulations using combined scheduled and direct activation (right) for a ramping event of 2 GW in the upward direction in 1 hour for BRP worst case with 2000 MW of FRR

2.1.4 Downward direction using a combination of scheduled and direct activation of mFRR means

Scenario 3,0 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
Deep-2p5GW	Worst Scenario	1104	375	42	750	0	1500	0
Deep-2p5GW	Worst Scenario	1500	375	7	750	0	1500	0
Deep-2p5GW	Worst Scenario	2000	375	7	750	0	1500	0
Deep-2p5GW	Worst Scenario	2500	375	7	750	0	1500	0
Deep-2p5GW	Best Scenario	1104	375	4	750	0	1500	0
Deep-2p5GW	Best Scenario	1500	375	4	750	0	1500	0
Deep-2p5GW	Best Scenario	2000	375	4	750	0	1500	0
Deep-2p5GW	Best Scenario	2500	375	4	750	0	1500	0
Deep-2p0GW	Worst Scenario	1104	375	0	750	0	1500	0
Deep-2p0GW	Worst Scenario	1500	375	0	750	0	1500	0
Deep-2p0GW	Worst Scenario	2000	375	2	750	0	1500	0
Deep-2p0GW	Worst Scenario	2500	375	2	750	0	1500	0
Deep-2p0GW	Best Scenario	1104	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	1500	375	1	750	0	1500	0
Deep-2p0GW	Best Scenario	2000	375	1	750	0	1500	0
Deep-2p0GW	Best Scenario	2500	375	1	750	0	1500	0
Deep-1p5GW	Worst Scenario	1104	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1104	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2500	375	0	750	0	1500	0

Table 4 – *Results for simulated downward ramping events in 60 minutes for 3.0 GW offshore generation*

As explained more in details for the upward ramping events, the combination of scheduled and direct activation also provides a positive impact for the downward ramping events.

As for the upward ramp, this effect can clearly be observed for the 2.5 GW ramping event in the downward direction, where the violation of threshold 1 is still present for the worst case of BRP reaction but where the duration has significantly change from 34 minutes to an acceptable level of 7 minutes for the higher mFRR volumes. The violation for the scenario with only contracted reserve capacity is still present as the 15-minute threshold is exceeded but the duration is reduced from 69 minutes to 42 minutes. The fact that the violation is still present is related to the lower FRR volume which is not capable of covering the highest peak of the system imbalance until the moment the BRP coverage starts increasing towards 100%.

In comparison to the ramping event in the upward direction, the positive impact can also be clearly observed for the 2.0 GW ramping down events.

2.2 Storm events

The simulation for storm events were performed for some specific storm events which were selected in the 37 year data series, provided by DTU, to cover a wide range of most extreme storm events. As displayed in Table 5, specific storm events for 3.0 GW installed offshore capacity were selected representing various downward ramp rates and maximum loss of power. The dates are later used as reference to show the results for each storm event. In the simulation model, the availability of slow-starting units that can be mobilized through the actual storm procedure is not explicitly covered. This is further discussed in the analysis of the results.

3,0 GW of installed offshore capacity									
Date	Storm Technology	Storm start time	Storm end time	Minimum power	1hRamp_min	1hRamp_max	3hRamp_min	3hRamp_max
1986-03-24	Tech B with HWRT Deep	10u40	17u10	585	-1377	2356	-2357	2411
1987-03-27	Tech B with HWRT Deep	6u15	22u55	0	-840	2361	-1837	3000
1987-10-16	Tech B with HWRT Deep	21u30	10u10	0	-1108	2880	-1900	3000
1990-02-12	Tech B with HWRT Deep	4u30	9u35	333	-2517	2114	-2613	2659
2007-01-18	Tech B with HWRT Deep	6u45	22u50	0	-2592	2839	-2981	3000

Table 5 – Details on selected storm events for 3.0 GW offshore generation

2.2.1 Scheduled activation of mFRR means

Scenario 3,0 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
24/03/1986	Worst Scenario	1104	375	0	750	0	1500	0
	Worst Scenario	1500	375	0	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
27/03/1987	Worst Scenario	1104	375	92	750	0	1500	0
	Worst Scenario	1500	375	0	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
12/02/1990	Worst Scenario	1104	375	29	750	0	1500	0
	Worst Scenario	1500	375	27	750	0	1500	0
	Worst Scenario	2000	375	27	750	0	1500	0
	Worst Scenario	2500	375	27	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
18/01/2007	Worst Scenario	1104	375	120	750	0	1500	0
	Worst Scenario	1500	375	23	750	0	1500	0
	Worst Scenario	2000	375	23	750	0	1500	0
	Worst Scenario	2500	375	23	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0

Table 6 – Results for simulated storm events for 3.0 GW offshore generation

Table 6 displays significantly long duration of violation of threshold 1 for storm events on 27/03/1987 and 18/01/2007, but only for the worst case BRP scenario where only the contracted reserve capacity is considered as FRR volume. Both storms represent a total loss of power of around 3.0 GW, for which the FRR volume is insufficient. The remaining system imbalance is due to a coverage of the BRP of only 40% during the cut-off phase. The FRR volume will only be sufficient as of a certain moment in time for which the BRP is increasing coverage to 100% over 2 hours. Due to the fact that the cut-off phase may extend of a longer period and the BRP takes 2 hours to cover 100% of the power loss, the violation of the threshold 1 shows a high duration (92 and 120 minutes).

The storm on 12/02/1990 shows lower values in violation for threshold 1, which is due to a lower power loss of 2.5 GW. The violations are not caused by insufficient FRR means, but are related to the delay in mFRR activation in comparison to the system imbalance. This also explains why the duration of the violations are limited while the cut-out phase of the storm event also takes a longer time as a ramping event. It also explains the violation for all worst case BRP scenarios.

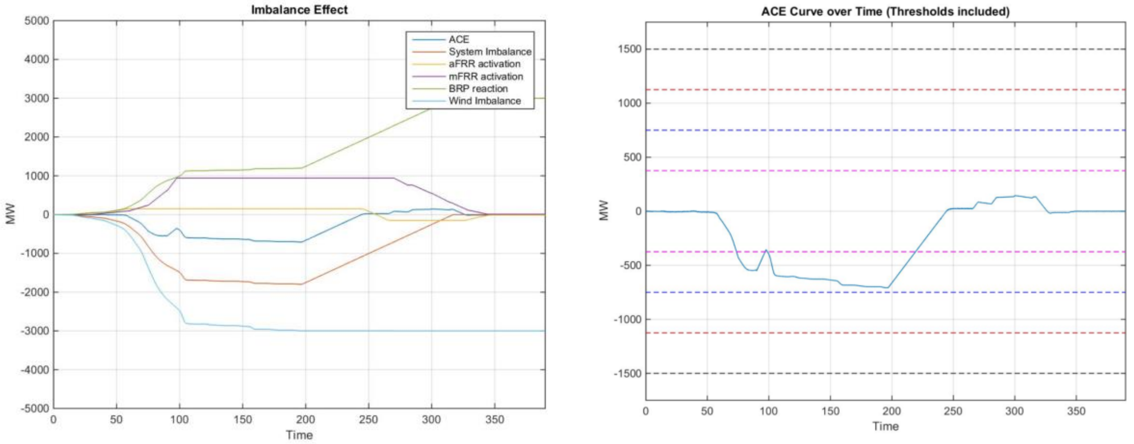

Figure 4– ***Plots visualizing the simulated data (left) and Area Control Error compared to the thresholds used for validation (right) for a storm event with a drop of approx. 3.0 GW for BRP worst case with 1104 MW*** **of FRR**

As mentioned above, Figure 4 displays the BRP reaction and activation of aFRR and mFRR means during the course of the simulation to compensate for the cut-out phase of a storm event related to offshore generation. The vertical axis represents the power values in MW, while the horizontal axis displays the time in minutes. The same axes are used by the plot on the right which contains a detailed plot for the Area Control Error with an indication of the thresholds used for validation of the event.

The System Imbalance achieves its maximum value at the end of the cut-out phase of the storm event, as the BRP only covers 40% of the power deviation during the cut-out phase, after which a linear increase to 100% coverage after 2 hours occurs. The highest values of System Imbalance is however not fully compensated by the activation of FRR means, for which the highest peak of Area Control Error occurs at the moment of highest System Imbalance at the end and even after the cut-out phase. This is related to the fact that there is not enough FRR in the system to cover the highest observed System Imbalance, which is more significant than the delay in mFRR activation in comparison to the system imbalance. The remaining imbalance is only resolved as of minutes 225 where the BRP coverage has already increased to more than 50%. This explains why only the worst case BRP scenario with only contracted reserve volumes as FRR lead to a violation of threshold 1.

2.2.2 Combination of scheduled and direct activation of mFRR means

As the violations for the extreme storms on 27/03/1987 and 18/01/2007 are fully related to insufficient mFRR volume for the scenario where only the contracted reserve capacity is taken into account to cover the system imbalance, the direct activation will not change anything to the violations monitored for these events.

As the violations for the storm on 12/02/1990 is mainly related to the delay in mFRR activation, where even the scenario with only contracted reserve capacity is sufficient to cover the system imbalance, including the direct activation in the model resulted in resolving the initial violations. This can be observed in the results displayed in Table 7.

Scenario 3,0 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
24/03/1986	Worst Scenario	1104	375	0	750	0	1500	0
	Worst Scenario	1500	375	0	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
27/03/1987	Worst Scenario	1104	375	87	750	0	1500	0
	Worst Scenario	1500	375	0	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
12/02/1990	Worst Scenario	1104	375	8	750	0	1500	0
	Worst Scenario	1500	375	6	750	0	1500	0
	Worst Scenario	2000	375	6	750	0	1500	0
	Worst Scenario	2500	375	2	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
18/01/2007	Worst Scenario	1104	375	119	750	0	1500	0
	Worst Scenario	1500	375	5	750	0	1500	0
	Worst Scenario	2000	375	5	750	0	1500	0
	Worst Scenario	2500	375	5	750	0	1500	0
	Best Scenario	1104	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0

Table 7 – Results for simulated storm events for 3.0 GW offshore generation including direct activation

3. Offshore installed capacity of 4.4 GW

3.1 Extreme ramping events

Similarly to the analysis done for 3.0 GW installed offshore capacity, for 4.4 GW capacity the events also focused on 60 minutes ramping events. For each event, a total of 8 simulations have been performed, taking into account the defined scenarios for BRP reaction and the available balancing energy. The reference case contains an activation of balancing energy by means of scheduled activation, with exception of aFRR balancing capacity which is activated continuously and automatically by the LFC controller, the evaluation is made using the same validation criteria introduced in the previous sub-section.

3.1.1 Upward direction using scheduled activation of mFRR means

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
_Deep_4p0GW_	Worst Scenario	1246	375	83	750	62	1500	1
_Deep_4p0GW_	Worst Scenario	1500	375	74	750	55	1500	0
_Deep_4p0GW_	Worst Scenario	2000	375	59	750	39	1500	0
_Deep_4p0GW_	Worst Scenario	2500	375	42	750	28	1500	0
_Deep_4p0GW_	Best Scenario	1246	375	48	750	28	1500	0
_Deep_4p0GW_	Best Scenario	1500	375	41	750	16	1500	0
_Deep_4p0GW_	Best Scenario	2000	375	38	750	16	1500	0
_Deep_4p0GW_	Best Scenario	2500	375	47	750	16	1500	0
_Deep_3p5GW_	Worst Scenario	1246	375	84	750	62	1500	0
_Deep_3p5GW_	Worst Scenario	1500	375	72	750	49	1500	0
_Deep_3p5GW_	Worst Scenario	2000	375	48	750	25	1500	0
_Deep_3p5GW_	Worst Scenario	2500	375	48	750	25	1500	0
_Deep_3p5GW_	Best Scenario	1246	375	44	750	7	1500	0
_Deep_3p5GW_	Best Scenario	1500	375	29	750	7	1500	0
_Deep_3p5GW_	Best Scenario	2000	375	38	750	7	1500	0
_Deep_3p5GW_	Best Scenario	2500	375	38	750	7	1500	0
_Deep_3p0GW_	Worst Scenario	1246	375	83	750	29	1500	0
_Deep_3p0GW_	Worst Scenario	1500	375	70	750	0	1500	0
_Deep_3p0GW_	Worst Scenario	2000	375	43	750	0	1500	0
_Deep_3p0GW_	Worst Scenario	2500	375	43	750	0	1500	0
_Deep_3p0GW_	Best Scenario	1246	375	21	750	0	1500	0
_Deep_3p0GW_	Best Scenario	1500	375	21	750	0	1500	0
_Deep_3p0GW_	Best Scenario	2000	375	17	750	0	1500	0
_Deep_3p0GW_	Best Scenario	2500	375	17	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	1246	375	49	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	1500	375	37	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2000	375	37	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2500	375	37	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1246	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2500	375	0	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1246	375	21	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1500	375	21	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2000	375	21	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2500	375	21	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1246	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1246	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1246	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2500	375	0	750	0	1500	0

Table 8 – Results for simulated upward ramping events in 60 minutes for 4.4 GW offshore generation

For the scenarios involving 4.4 GW installed capacity, the impact is higher comparing to the 3.0 GW installed capacity. Most of the cases are not acceptable. All the scenarios with worst case BRP reaction resulted in violations, which includes in most cases a violation of the Threshold 2. The worst violations has been observed for the scenario involving a ramping of 4.0 GW corresponding to 90 % of the total installed capacity which resulted in a triggering and violation of the Threshold 3 (true status 1 which lasted continuously for 17 minutes). Such case, corresponds in the most conservative assumption as we consider lowest mFFR means and the worst BRP reaction, still this gives an idea on the possible impact of such events if no mitigation or actions are implemented.

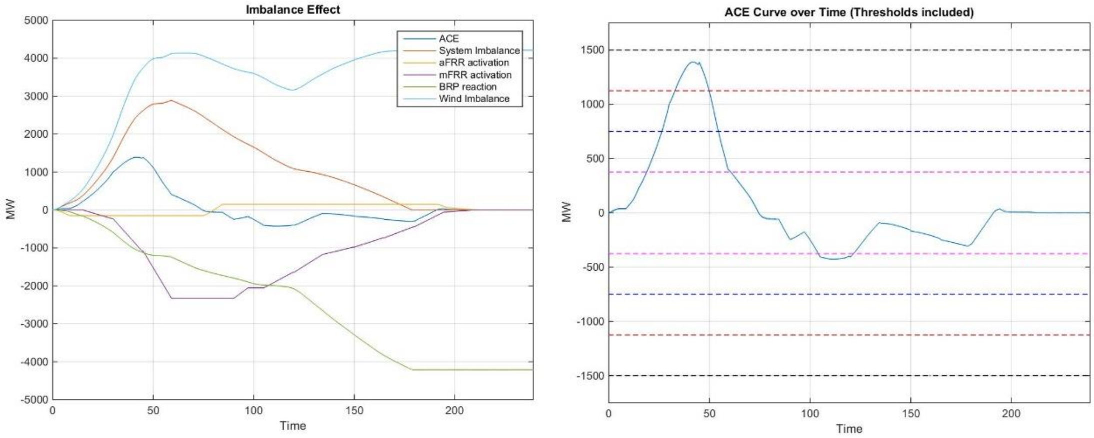

Figure 5 – Plots visualizing the simulated data (left) and Area Control Error compared to the thresholds used for validation (right) for a ramping event of 4.0 GW in the upward direction in 1 hour for BRP worst case with 2500 MW of FRR

Figure 5 illustrates the overall system behavior during the ramping event considering an available volume of a total FRR reserve of 2500 MW (which includes both automatic and manually activated mFRR means), the ACE evolution resulted in considerable extend of violations beyond the defined thresholds.

On the other hand, considering a worst BRP scenario, a good extend of the observed violation are mitigated except for the most extreme events as certain violations are also observed even considering the best case BRP reaction for ramping events equal or higher than 3.0 GW. In fact, the dynamic of the System Imbalance achieves its maximum value at the end of the ramping event, as the BRP only covers 30% of the power deviation during the ramping event.

On the other hand due to the activation time, the total deployment of manual and automatic restoration reserve is rather achieved after the peak of SI, which helps mitigate the impact of imbalance until the BRPs reaction would restore the balance of the system.

Similarly to previously covered scenarios, FRR volumes were important to limit the highest observed System Imbalance, however the mFRR activation shows a delay in comparison to the system imbalance during the first 40 minutes which is due to the manual scheduled activation of mFRR by the operator by use of scheduled activation, which is in line with the objective of the TSO for incentivizing the market players to balance their portfolios as much as possible.

3.1.2 Downward direction using scheduled activation of mFRR means

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
Deep-3p5GW	Worst Scenario	1246	375	71	750	46	1500	0
Deep-3p5GW	Worst Scenario	1500	375	61	750	29	1500	0
Deep-3p5GW	Worst Scenario	2000	375	36	750	22	1500	0
Deep-3p5GW	Worst Scenario	2500	375	36	750	22	1500	0
Deep-3p5GW	Best Scenario	1246	375	28	750	0	1500	0
Deep-3p5GW	Best Scenario	1500	375	27	750	0	1500	0
Deep-3p5GW	Best Scenario	2000	375	30	750	0	1500	0
Deep-3p5GW	Best Scenario	2500	375	30	750	0	1500	0
Deep-3p0GW	Worst Scenario	1246	375	56	750	7	1500	0
Deep-3p0GW	Worst Scenario	1500	375	44	750	0	1500	0
Deep-3p0GW	Worst Scenario	2000	375	36	750	0	1500	0
Deep-3p0GW	Worst Scenario	2500	375	36	750	0	1500	0
Deep-3p0GW	Best Scenario	1246	375	19	750	0	1500	0
Deep-3p0GW	Best Scenario	1500	375	19	750	0	1500	0
Deep-3p0GW	Best Scenario	2000	375	19	750	0	1500	0
Deep-3p0GW	Best Scenario	2500	375	19	750	0	1500	0
Deep-2p5GW	Worst Scenario	1246	375	53	750	0	1500	0
Deep-2p5GW	Worst Scenario	1500	375	34	750	0	1500	0
Deep-2p5GW	Worst Scenario	2000	375	34	750	0	1500	0
Deep-2p5GW	Worst Scenario	2500	375	34	750	0	1500	0
Deep-2p5GW	Best Scenario	1246	375	0	750	0	1500	0
Deep-2p5GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-2p5GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-2p5GW	Best Scenario	2500	375	0	750	0	1500	0
Deep-2p0GW	Worst Scenario	1246	375	20	750	0	1500	0
Deep-2p0GW	Worst Scenario	1500	375	20	750	0	1500	0
Deep-2p0GW	Worst Scenario	2000	375	20	750	0	1500	0
Deep-2p0GW	Worst Scenario	2500	375	20	750	0	1500	0
Deep-2p0GW	Best Scenario	1246	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-2p0GW	Best Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1246	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Worst Scenario	2500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1246	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	1500	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2000	375	0	750	0	1500	0
Deep-1p5GW	Best Scenario	2500	375	0	750	0	1500	0

Table 9- Results for simulated downward ramping events in 60 minutes for 4.4 GW offshore generation

Table 9 shows the results related to ramping events in the downward direction which occur within a period of 1 hour. Only ramping events lower than 2 GW presented acceptable results, the remaining events with higher scale were systematically not acceptable for the worst case scenario of BRP reaction and on limited cases for the Best case scenarios as well (-3 GW and -3.5 GW).

As seen in the above Table, the worst violations have been observed for the most extreme event (-3.5 GW) where only the minimum contracted FRR volumes (1246 MW) are considered with a scenarios characterized by worst BRP reaction, with violation of the T1 and the T2 limits. While such scenario, represents the most conservative sensitivity considering the possible challenge to predict such events it is important to have a good view on the repercussion of such events especially in case of ramping down events as the negative energy imbalance is more challenging to compensate comparing to an upward ramping scenario.

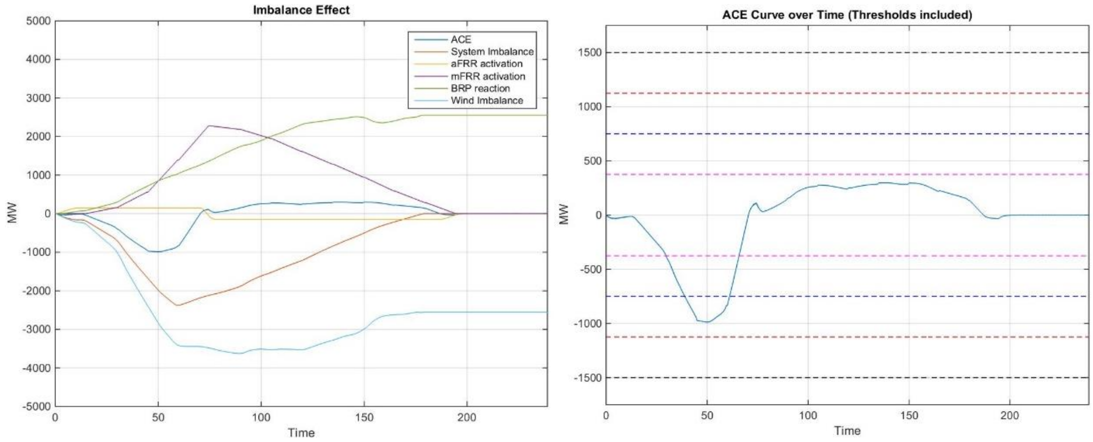

Figure 6– Plots visualizing the simulated data (left) and Area Control Error compared to the thresholds used for validation (right) for a ramping event of - 3.5 GW in the downward direction in 1 hour for BRP worst case with 2500 MW of FRR

Figure 6 displays the overall observed behavior in the system including the BRP reaction and activation of aFRR and mFRR means during the course of the simulation to compensate for the deviation of offshore generation under the form a 3.5 GW downward ramping event . The System Imbalance reaches its maximum value as per the end of the ramping event and after the maximum ACE deviation. This is mainly due to the high gradient of the ramping event, in such case while the increase of available FRR volume helps reducing the imbalance in term of Energy throughout the duration of the event. On the other hand, the nadir of the ACE will remain unchanged beyond a maximum volume of FRR and thus resulting in similar violation level for the 2000 MW and 2500 MW FRR scenario, this is mainly explained by the fact that the resulting mismatch is due to the lag of mFRR activations comparing to the gradient of the ramping. A further improvement of the violations mitigations would either require better compensation of BRP at the initial phase of the ramping event of faster mFRR means activation as explained in previous upward ramping cases.

In the actual section, an extra sensitivity analysis is included to illustrate the potential impact of more available volumes of automatic activation of restoration reserves (considering 5 minutes of full activation time), the sensitivity is applied to the base case scheduled activation considering the same total available FRR volume (only 2000 and 2500 MW scenarios). As summarized in Table 10, which corresponds to the 3.5 GW ramping down event the volumes of 600 MW and 400 MW aFRR are considered respectively for 2500 MW and 2000 MW total FRR. The chosen event, illustrated a limitation of including higher volumes of mFRR means as the violation level remained constant despite an increase of mFRR means due to the high gradient of the ramping event. Logically the additional aFRR shares resulted in improvement of the imbalance control and reduction of violation duration for both threshold T1 and T2. It is however important to mention that higher share of aFRR available volumes exchanges depend on the availability of cross-border and the remaining capacity of usage and exchange of mFRR volumes.

Scenario	Sensitivity	aFRR	FRR	T1	Continous duration>T1	T2	Continous duration>T2	T3	Violation	Scenario
Ramping of -3,5 GW event	Base case	177	2500	375	36	750	22	1500	0	Worst Scenario
		177	2000	375	36	750	22	1500	0	Worst Scenario
	Additional aFRR	600	2500	375	25	750	0	1500	0	Worst Scenario
		400	2000	375	27	750	0	1500	0	Worst Scenario

Table 10 ***Sensitivity impact of additional aFRR share in the total foreseen FRR volumes***

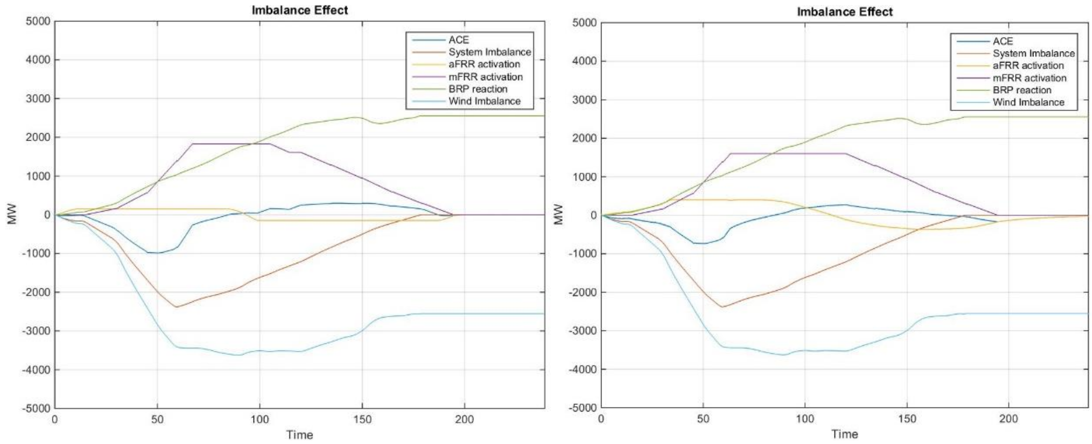

Figure 7- Plots visualizing the base case simulation base case scenario (left) and the sensitivity scenario with additional aFRR share (right) for a ramping event of 3.5 GW in the downward direction in 1 hour for BRP worst case with 2000 MW of FRR

The above figure, illustrates the detailed behavior during 3.5 GW storm event for both base case scenario and the sensitivity of additional aFRR shares (400 MW).

The impact can be clearly observed at the initial phase of the storm as the automatic aFRR activation helps containing more rapidly during since the initial phase of the ramping event this is mainly due to the Faster FAT (5 minutes comparing to 15 minutes for mFRR) as well as the automatic and continuous activation that correct directly the ACE deviation. This results less violation duration and lower energy imbalance throughout the event as it can be seen in the ACE dynamic. It is however, important to remind that such larger aFRR volumes remain not guaranties and effective only if there are dedicated cross-border capacity available which is likely to be impacted by other simultaneous events in the North Sea (Borssele and Dunkirk). Finally, it is important to mention that such change in term of available aFRR volumes requires a full re-tuning of the LFC controller parameters specifically the anti-windup, Ki and Kp regulation settings. The actual model has been adapted to accommodate such sensitivity with acceptable behavior that can be used as a reference to show the general impact, the precise expected performance would therefore depend on the exact final tuning of the settings.

3.1.3 Upward direction using a combination of scheduled and direct activation of mFRR means

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
_Deep_4p0GW_	Worst Scenario	1246	375	82	750	61	1500	1
_Deep_4p0GW_	Worst Scenario	1500	375	73	750	54	1500	0
_Deep_4p0GW_	Worst Scenario	2000	375	58	750	21	1500	0
_Deep_4p0GW_	Worst Scenario	2500	375	33	750	21	1500	0
_Deep_4p0GW_	Best Scenario	1246	375	47	750	10	1500	0
_Deep_4p0GW_	Best Scenario	1500	375	40	750	0	1500	0
_Deep_4p0GW_	Best Scenario	2000	375	21	750	0	1500	0
_Deep_4p0GW_	Best Scenario	2500	375	21	750	0	1500	0
_Deep_3p5GW_	Worst Scenario	1246	375	82	750	60	1500	0
_Deep_3p5GW_	Worst Scenario	1500	375	70	750	30	1500	0
_Deep_3p5GW_	Worst Scenario	2000	375	24	750	15	1500	0
_Deep_3p5GW_	Worst Scenario	2500	375	24	750	15	1500	0
_Deep_3p5GW_	Best Scenario	1246	375	23	750	4	1500	0
_Deep_3p5GW_	Best Scenario	1500	375	16	750	4	1500	0
_Deep_3p5GW_	Best Scenario	2000	375	16	750	4	1500	0
_Deep_3p5GW_	Best Scenario	2500	375	16	750	4	1500	0
_Deep_3p0GW_	Worst Scenario	1246	375	56	750	28	1500	0
_Deep_3p0GW_	Worst Scenario	1500	375	37	750	0	1500	0
_Deep_3p0GW_	Worst Scenario	2000	375	0	750	0	1500	0
_Deep_3p0GW_	Worst Scenario	2500	375	0	750	0	1500	0
_Deep_3p0GW_	Best Scenario	1246	375	0	750	0	1500	0
_Deep_3p0GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_3p0GW_	Best Scenario	2000	375	2	750	0	1500	0
_Deep_3p0GW_	Best Scenario	2500	375	0	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	1246	375	16	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	1500	375	13	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2000	375	13	750	0	1500	0
_Deep_2p5GW_	Worst Scenario	2500	375	13	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1246	375	7	750	0	1500	0
_Deep_2p5GW_	Best Scenario	1500	375	7	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2000	375	7	750	0	1500	0
_Deep_2p5GW_	Best Scenario	2500	375	7	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1246	375	0	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	1500	375	0	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2000	375	0	750	0	1500	0
_Deep_2p0GW_	Worst Scenario	2500	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1246	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_2p0GW_	Best Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1246	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Worst Scenario	2500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1246	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	1500	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2000	375	0	750	0	1500	0
_Deep_1p5GW_	Best Scenario	2500	375	0	750	0	1500	0

Table 11 - Results for simulated upward ramping events in 60 minutes for 4.4 GW offshore generation with combined activations

As explained in the 3.0 GW scenarios, the combined activation of both scheduled and direct activation mFRR means generally leads to less delay in mFRR means. Which would limit generally the imbalance in energy and limit the peak of the ACE, thus leading toward lower extend of violations. The violation duration has been reduced in all cases, still violations of the Threshold 3 is observed for the 4GW ramping event with minimal FRR means (1246 MW), the specific limitation in such case consists the shortage of the activation that cannot adequately compensate the imbalance.

On the other hand, for the same 4.0 GW ramping event under a best BRP balancing scenario most of the T2 violation are reduced except for the minimum mFRR means cases. The fact that the violation is still present is probably related to the lower FRR volume which is not capable of covering the highest peak of the system imbalance until the moment the BRP coverage starts increasing towards 100%.

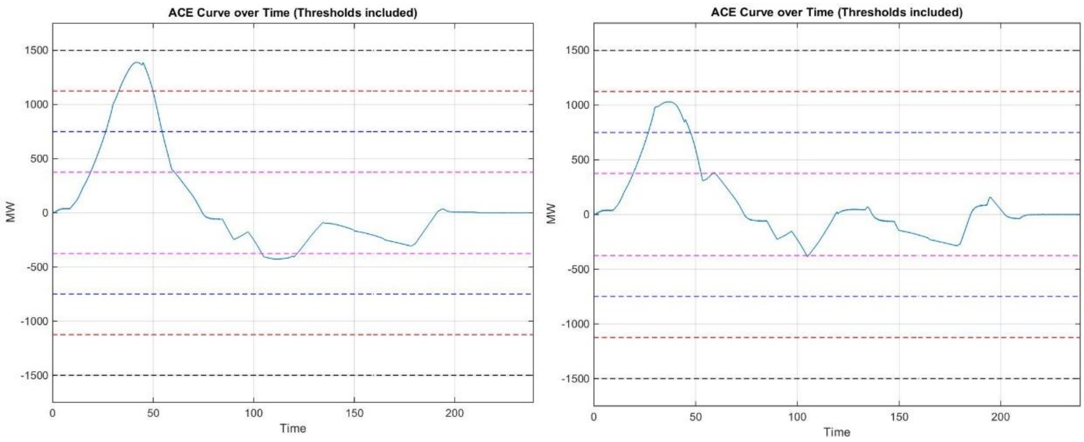

Figure 8 - **Plots visualizing the base case simulation (left) and the combined direct and scheduled activation (right) for a upward ramping event of 4.0 GW in 1 hour for BRP worst case with 2500 MW of FRR**

Figure 8 illustrates the two simulations based on default scheduled activation and a combination of scheduled and direct activation. It can be observed in the curve that in term of Energy Imbalance and extreme peak of ACE the combined activation provide better outcomes. This is specific to events that are characterized with very fast and large scale ramping as the scale of the activated volumes would not completely suffice to eliminate violations. Nevertheless, it is again important to mention that such activations are complex as they might result in over-compensations, therefore the simulations using a combination of scheduled and direct activation should be considered as a sensitivity analysis instead of a reference scenario.

3.1.4 Downward direction using a combination of scheduled and direct activation of mFRR means

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation	FRR	Scenario
Deep-3p5GW	Worst Scenario	1246	375	69	750	33	1500	0	1246	Worst Scenario
Deep-3p5GW	Worst Scenario	1500	375	60	750	11	1500	0	1500	Worst Scenario
Deep-3p5GW	Worst Scenario	2000	375	27	750	0	1500	0	2000	Worst Scenario
Deep-3p5GW	Worst Scenario	2500	375	27	750	0	1500	0	2500	Worst Scenario
Deep-3p5GW	Best Scenario	1246	375	16	750	0	1500	0	1246	Best Scenario
Deep-3p5GW	Best Scenario	1500	375	16	750	0	1500	0	1500	Best Scenario
Deep-3p5GW	Best Scenario	2000	375	16	750	0	1500	0	2000	Best Scenario
Deep-3p5GW	Best Scenario	2500	375	16	750	0	1500	0	2500	Best Scenario
Deep-3p0GW	Worst Scenario	1246	375	36	750	6	1500	0	1246	Worst Scenario
Deep-3p0GW	Worst Scenario	1500	375	17	750	0	1500	0	1500	Worst Scenario
Deep-3p0GW	Worst Scenario	2000	375	3	750	0	1500	0	2000	Worst Scenario
Deep-3p0GW	Worst Scenario	2500	375	5	750	0	1500	0	2500	Worst Scenario
Deep-3p0GW	Best Scenario	1246	375	5	750	0	1500	0	1246	Best Scenario
Deep-3p0GW	Best Scenario	1500	375	5	750	0	1500	0	1500	Best Scenario
Deep-3p0GW	Best Scenario	2000	375	18	750	0	1500	0	2000	Best Scenario
Deep-3p0GW	Best Scenario	2500	375	18	750	0	1500	0	2500	Best Scenario
Deep-2p5GW	Worst Scenario	1246	375	20	750	0	1500	0	1246	Worst Scenario
Deep-2p5GW	Worst Scenario	1500	375	17	750	0	1500	0	1500	Worst Scenario
Deep-2p5GW	Worst Scenario	2000	375	17	750	0	1500	0	2000	Worst Scenario
Deep-2p5GW	Worst Scenario	2500	375	17	750	0	1500	0	2500	Worst Scenario
Deep-2p5GW	Best Scenario	1246	375	0	750	0	1500	0	1246	Best Scenario
Deep-2p5GW	Best Scenario	1500	375	0	750	0	1500	0	1500	Best Scenario
Deep-2p5GW	Best Scenario	2000	375	0	750	0	1500	0	2000	Best Scenario
Deep-2p5GW	Best Scenario	2500	375	0	750	0	1500	0	2500	Best Scenario
Deep-2p0GW	Worst Scenario	1246	375	0	750	0	1500	0	1246	Worst Scenario
Deep-2p0GW	Worst Scenario	1500	375	0	750	0	1500	0	1500	Worst Scenario
Deep-2p0GW	Worst Scenario	2000	375	0	750	0	1500	0	2000	Worst Scenario
Deep-2p0GW	Worst Scenario	2500	375	0	750	0	1500	0	2500	Worst Scenario
Deep-2p0GW	Best Scenario	1246	375	0	750	0	1500	0	1246	Best Scenario
Deep-2p0GW	Best Scenario	1500	375	0	750	0	1500	0	1500	Best Scenario
Deep-2p0GW	Best Scenario	2000	375	0	750	0	1500	0	2000	Best Scenario
Deep-2p0GW	Best Scenario	2500	375	0	750	0	1500	0	2500	Best Scenario
Deep-1p5GW	Worst Scenario	1246	375	0	750	0	1500	0	1246	Worst Scenario
Deep-1p5GW	Worst Scenario	1500	375	0	750	0	1500	0	1500	Worst Scenario
Deep-1p5GW	Worst Scenario	2000	375	0	750	0	1500	0	2000	Worst Scenario
Deep-1p5GW	Worst Scenario	2500	375	0	750	0	1500	0	2500	Worst Scenario
Deep-1p5GW	Best Scenario	1246	375	0	750	0	1500	0	1246	Best Scenario
Deep-1p5GW	Best Scenario	1500	375	0	750	0	1500	0	1500	Best Scenario
Deep-1p5GW	Best Scenario	2000	375	0	750	0	1500	0	2000	Best Scenario
Deep-1p5GW	Best Scenario	2500	375	0	750	0	1500	0	2500	Best Scenario

Table 12- Results for simulated upward ramping events in 60 minutes for 4.4 GW offshore generation with combined activations

Similarly to the upward fast ramping events, downward events simulation using a combination of the default scheduled activation and the direct activation reduced the overall violation durations as well as the overall energy imbalance. The reduction is notably more visible on the cases where additional mFRR means activation in the base case did not result in improvements as the issue is rather related to the slow reaction to mFRR deployment comparing to the high gradient of such events.

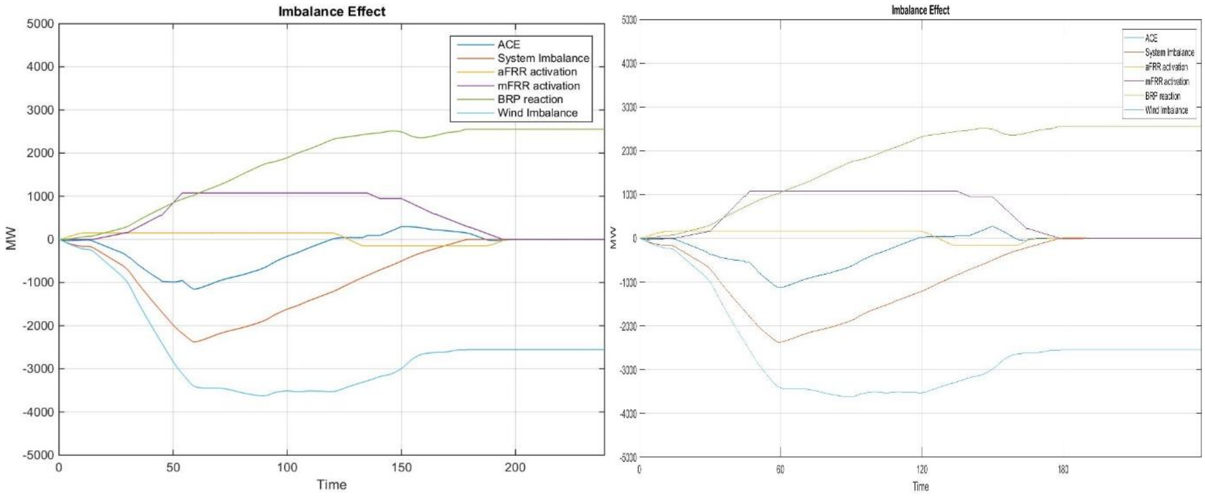

Figure 9 - Plots visualizing the base case simulation (left) and the combined direct and scheduled activation (right) for a ramping event of -3.5 GW in the upward direction in 1 hour for BRP worst case with 1246 MW of FRR

Similarly to the upward ramping case, the Figure 9 Figure 9illustrates a comparison between two simulations covering only default scheduled activation (left) and a combined activation of both scheduled and direct activation. It can be observed that for both energy imbalance and the threshold violation the combined activation provide better outcomes. This is specifically more relevant to events that are characterized with very fast and large scale ramping gradients. In such cases, the FRR deployment volumes would not completely suffice to eliminate violations that are related to the lag of activation with respect to the gradient of the imbalance. In the actual case, while the extreme observed values remain similar, the overall energy imbalance for both initial and final phase of the event are improved, full mitigation of the Threshold 2 violations can be observed for additional FRR volumes in the case of 2000 MW and 2500 MW.

3.2 Storm events

Similarly to the 3.0 GW installed capacity, the simulation were performed for some specific storm events which were selected in the 37 year data series provided by DTU, covering a wide range of most extreme storm events. As displayed in the below table, specific storm events for 4.4 GW installed offshore capacity were selected representing various downward ramp rates and maximum loss of power. The dates are later used as reference to show the results for each storm event.

4,4 GW of installed offshore capacity								
Day	**Storm Technology**	**Storm start time**	**Storm end time**	**Minimum power**	**1hRamp_min**	**1hRamp_max**	**3hRamp_min**	**3hRamp_max**
1984-01-03	Tech B with HWRT Deep	0u00	23u55	409	-477	3161	-624	3960
1986-03-24	Tech B with HWRT Deep	10u10	17u10	579	-2167	3763	-3749	3817
1987-03-27	Tech B with HWRT Deep	4u10	23u20	0	-1325	3750	-2587	4400
1987-10-16	Tech B with HWRT Deep	21u20	10u10	0	-1833	4083	-2914	4381
1990-02-12	Tech B with HWRT Deep	2u15	9u50	815	-2867	2473	-3350	3569
1990-03-01	Tech B with HWRT Deep	0u00	14u20	3863	-325	2614	-535	3290
1993-01-24	Tech B with HWRT Deep	17u10	12u25	833	-1612	2095	-2121	2426
2007-01-18	Tech B with HWRT Deep	6u41	22u50	0	-3333	3208	-4361	4400
2011-12-13	Tech B with HWRT Deep	22u45	7u20	826	-1613	2476	-3532	3420
2016-03-28	Tech B with HWRT Deep	00u00	15u15	929	-2224	2547	-3413	3049

Table 13- Details on selected storm events for 4.4 GW offshore installed generation

3.2.1 Scheduled activation of mFRR means

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
24/03/1986	Worst Scenario	1246	375	66	750	37	1500	0
	Worst Scenario	1500	375	47	750	3	1500	0
	Worst Scenario	2000	375	12	750	0	1500	0
	Worst Scenario	2500	375	12	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
27/03/1987	Worst Scenario	1246	375	262	750	207	1500	0
	Worst Scenario	1500	375	223	750	123	1500	0
	Worst Scenario	2000	375	79	750	0	1500	0
	Worst Scenario	2500	375	24	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
16/10/1987	Worst Scenario	1246	375	121	750	92	1500	0
	Worst Scenario	1500	375	101	750	60	1500	0
	Worst Scenario	2000	375	40	750	0	1500	0
	Worst Scenario	2500	375	7	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
12/02/1990	Worst Scenario	1246	375	106	750	47	1500	0
	Worst Scenario	1500	375	91	750	0	1500	0
	Worst Scenario	2000	375	32	750	0	1500	0
	Worst Scenario	2500	375	32	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
24/01/1993	Worst Scenario	1246	375	142	750	0	1500	0
	Worst Scenario	1500	375	17	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
18/01/2007	Worst Scenario	1246	375	137	750	113	1500	0
	Worst Scenario	1500	375	126	750	84	1500	0
	Worst Scenario	2000	375	72	750	13	1500	0
	Worst Scenario	2500	375	28	750	13	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
13/12/2011	Worst Scenario	1246	375	66	750	16	1500	0
	Worst Scenario	1500	375	25	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
28/03/2016	Worst Scenario	1246	375	80	750	25	1500	0
	Worst Scenario	1500	375	56	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0

Table 14- Results for simulated storm events for 4.4 GW offshore generation

The Table above displays significantly long duration of violation of Threshold 1 for storm events on 27/03/1987, 16/10/1987 and 18/01/2007, this is observed only for the worst case BRP scenario, maximum availability of mFRR means do have a major impact on the degree of the observed violations. Both storms represent a total loss of power of around 4.0 GW, for which even highest available FRR volume scenario (eg 2000 MW) still presents violations. The ability to solve completely the imbalance depends highly on the coverage of the BRP which in the worst case could correspond to only 40% during the cut-off phase. The FRR volume will only be sufficient, for limited storms impact whenever the BRPs are able to increase the coverage to 100% over 2 hours. Due to the fact that the cut-off phase may extend over a longer period and the BRP takes 2 hours to cover 100% of the power loss, the violations of the threshold 1 show high durations.

All the storms resulting in high rates of violations for both the thresholds 1 and 2, consisted of power losses higher than 4.0 GW within a duration of three hours. Considering the reaction of the BRP and the activated available FRR volumes, the residual imbalance of the system would last for important period resulting therefore in sustained violation of the fixed limits specifically the Target 1.

The storm on 12/02/1990 shows lower values in violation for threshold 1, which is due to a lower power loss of 2.5 GW. The violations are not caused by insufficient FRR means, but are related to the delay in mFRR activation in comparison to the system imbalance. This also explains why the duration of the violations are limited while the cut-out phase of the storm event also takes a longer time as a ramping event. It also explains the violation for all worst case BRP scenarios.

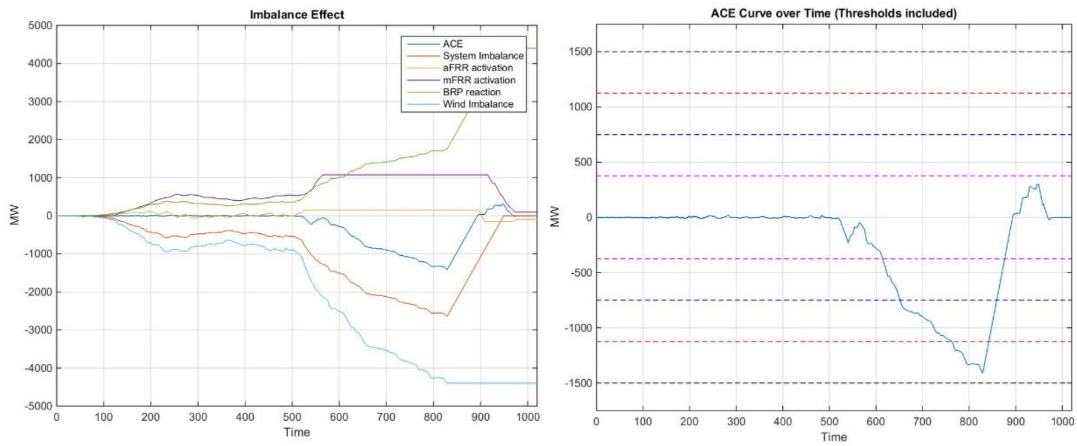

Figure 10 - Plots visualizing the simulated data (left) and Area Control Error compared to the thresholds used for validation (right) for a storm event with a drop of approx. 4.0 GW for BRP worst case with 1104 MW of FRR (event 27/03/1987)

Figure 10 illustrates the simulation results of the storm event equivalent to the historical event of the 27/03/1987, the storm lasted more than 12 hours, with a critical phase resulting in persistent imbalance throughout 6 hours. The first phase of the storm (up to 500 minutes in the figure) has been managed by relying on the BRP reaction and the activation of manual and automatic mFRR to cover the residual imbalance. The second phase of the storm is however characterized by a further loss of more than 3500 MW, considering the actual scenario (ie 1246 MW of FRR means) mFRR means exhaustion resulted in a large and sustained imbalance is the system relied mainly the imbalance correction did rely mainly on the BRP reaction. As displayed in the above Table, considering larger available FRR could significantly help mitigating the violations levels (eg only 24 minutes near to the Threshold 1 for 2500 MW FRR means availability).

3.2.2 Combination of scheduled and direct activation of mFRR means

Scenario 4,4 GW	Scenario	FRR	T1	Continous duration >T1 [min]	T2	Continous duration >T2 [min]	T3	Violation
24/03/1986	Worst Scenario	1246	375	65	750	35	1500	0
	Worst Scenario	1500	375	44	750	0	1500	0
	Worst Scenario	2000	375	3	750	0	1500	0
	Worst Scenario	2500	375	3	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
27/03/1987	Worst Scenario	1246	375	260	750	205	1500	0
	Worst Scenario	1500	375	220	750	119	1500	0
	Worst Scenario	2000	375	75	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
16/10/1987	Worst Scenario	1246	375	119	750	90	1500	0
	Worst Scenario	1500	375	99	750	56	1500	0
	Worst Scenario	2000	375	38	750	0	1500	0
	Worst Scenario	2500	375	3	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
12/02/1990	Worst Scenario	1246	375	86	750	45	1500	0
	Worst Scenario	1500	375	59	750	0	1500	0
	Worst Scenario	2000	375	4	750	0	1500	0
	Worst Scenario	2500	375	4	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
24/01/1993	Worst Scenario	1246	375	137	750	0	1500	0
	Worst Scenario	1500	375	15	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
18/01/2007	Worst Scenario	1246	375	136	750	105	1500	0
	Worst Scenario	1500	375	124	750	82	1500	0
	Worst Scenario	2000	375	71	750	0	1500	0
	Worst Scenario	2500	375	19	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
13/12/2011	Worst Scenario	1246	375	64	750	14	1500	0
	Worst Scenario	1500	375	23	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0
28/03/2016	Worst Scenario	2000	375	78	750	20	1500	0
	Worst Scenario	2000	375	53	750	0	1500	0
	Worst Scenario	2000	375	0	750	0	1500	0
	Worst Scenario	2500	375	0	750	0	1500	0
	Best Scenario	1246	375	0	750	0	1500	0
	Best Scenario	1500	375	0	750	0	1500	0
	Best Scenario	2000	375	0	750	0	1500	0
	Best Scenario	2500	375	0	750	0	1500	0

Table 15 - Results for simulated storm events for 4.4 GW offshore generation for combined scheduled and direct mFRR activations

While considering combined scheduled and direct activations, improvement remains relatively very marginal comparing to the magnitude of the observed violations. This is mainly due to the fact that most of the violation are rather related to the shortage of balancing means and BRP reaction (in the worst case scenario), which are sustained for relatively long period comparing to ramping events.