# APPENDIX ON ASSUMPTIONS FOR THE ASSESSMENT OF SHORT-TERM FLEXIBILITY

Version submitted to public consultation for the next Adequacy & Flexibility study 2024-34

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Besides an update of the prediction time series and the forced outage characteristics, and the update of the technical characteristics of end-user flexibility technologies, no other revisions are proposed to be implemented compared to the assumptions presented in the Adequacy and Flexibility Study 2021

# 1. Prediction data

Predictions made about the total load and renewable generation are based on the results of forecasting tools which are published on a real-time basis 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 of the tools which are used by market players.

- Time series for the real-time estimated **real-time total load, real-time onshore wind and solar power generation as well as the other distributed generation** are based measurements, monitoring and upscaling by Elia. The corresponding time series of forecasted values (day-ahead, intra-day and last forecast) are obtained from external service providers. Note that a correction is made to the forecast error when Elia activated a decremental bid on these units.
- The **measured real-time offshore wind power generation** and the corresponding forecasted values in this study are based on time series which are used in Elia's latest study on the system integration of a second wave of offshore generation in Belgium. In this framework, these time series are modelled by the Technical University of Denmark to represent the real-time generation and forecasts for the projected wind power plants in 2020 (2.3 GW), 2028 (3.0 GW), 2029 (4.4 GW) and 2030 (5.8 GW). This allowed estimated technology and topology of the future offshore wind power fleet to be taken into account. Furthermore, these time series also represent higher resolutions (up to 5 minutes) which is used to study the effect of fast variations. For these reasons, this data is selected over Elia's measurement and forecast data. More information on the modelling of the offshore data can be found in the study which is currently foreseen to be published in Q1 2022 in the framework of the MOG 2 study.

In order to take a representative dataset into account, two subsequent full years (2020 and 2021) are selected. The choice of years is driven by the availability of offshore wind power time series modelled by the Technical University of Denmark (DTU). Due to the planned offshore developments, which will more than double the installed generation capacity, the advantage of having more accurate offshore generation and forecast projections outweighed the use of the latest measurement and prediction data from 2022.

Total load, real-time onshore wind and solar power generation as well as the other distributed generation forecasts are corrected with **forecast improvements** towards 2034. An average cumulative improvement factor of 1% per year is taken into consideration between 2020-21 and 2034. This means that the forecast error is corrected to 99.00% of its value towards 2022, 98.01% for 2023 by means of a factor $(1 - 0.01)^y$ (in which 'y' is the year for which the forecast errors are calculated). This results in the original forecast errors from 2020-21 being reduced to 87.8% of their original value in 2034.

These improvements made to forecasting accuracy are mainly attributed to increasing geographical dispersion, which smooths out prediction errors. Note that no other significant improvements are expected for the weather forecast models (except for better predicting extreme weather conditions). Furthermore, the integration of new technologies such as electric vehicles, heat pumps and other decentral capacity are expected to result in new patterns which increase the complexity of forecasting algorithms.

# 2. Forced outage characteristics

The forced outage probability of power plants and the Nemo Link HVDC interconnector is based on the historical records of power plant outages between 2011 and 2020 (see Section 4.3 in the excel with input data) in which the parameter is determined per technology type. It is determined based on the historic amount of forced outages per year and used to determine the forced outage risks accounted for in the flexibility needs analyses. This parameter is to be distinguished from the average forced outage rate and the average forced outage duration, used in the adequacy simulations.

No forced outages for renewable generation, decentralised 'must run' generation (e.g. combined heat and power) or demand side management are accounted for. Demand side management volumes are typically based on aggregation and it is assumed that the forced outage probability is taken into account when determining the available capacity. The forced outages of renewable generation and decentralised 'must run' generation units are implicitly taken into account in the prediction and estimated generation profiles.

# 3. Technology characteristics

The technical characteristics concerning flexibility are based on a literature review, Elia's expertise and comments received from stakeholders during the previous consultations held on input data. A detailed overview of all the technical characteristics of each technology can be found in Section 4.4 in the excel with input data. An overview is summarised in Figure 1. The arrows depicted in the figure represent the direction in which the flexibility can be delivered. When the arrow is depicted in orange, the flexibility is not included in the calculations and the results due to uncertainty (e.g. as with nuclear generation units where the flexibility depends on several technical constraints), but can considered as additional flexibility which might be available under exceptional conditions.

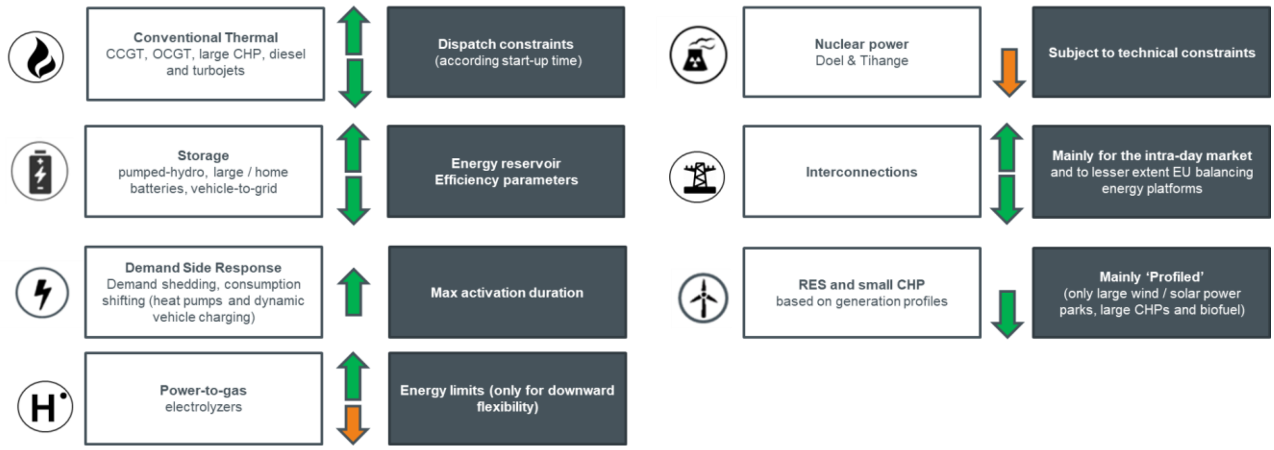


*Figure 1: summary of technological capabilities concerning flexibility*

Firstly, the ability to provide flexibility is determined by the **operational characteristics** (minimum up/down time, hot/warm/cold start-up time, transition time from hot to warm / warm to cold, minimum stable power, rated power and the ramp rate). In general, these constraints are particularly relevant for thermal power plants.

Secondly, where relevant, an **energy limit** is taken into account to represent the maximum duration a technology can be used to provide flexibility at its rated power. Although this is in general only relevant for non-thermal units (storage, demand side response), it may also apply to combined heat and power.

Thirdly, some particular technology assumptions are used to limit, where necessary, the **maximum flexibility which can be taken into account for each** type of flexibility needs considered in this study: ramping flexibility (able to react on a minutely basis), fast flexibility (able to be activated in 15 minutes) and slow flexibility (able to be activated in 5 hours). In general, this constraint is based on the difference between the scheduled output of the adequacy simulations, and the maximum rated power / minimum stable power of the technology unit.

- **Thermal generation**

**Nuclear power units** have been shown to provide flexibility, but this flexibility is subject to several technical limitations; for example, only some units are flexible and the flexibility of these units is limited in power, duration and frequency and depends on technical constraints such as the position in the fuel cycle. This makes it difficult to quantify the flexibility in a structural way and these units are therefore considered as non-flexible in the calculations. However, one can indeed assume that when assessing the results of the flexibility means, it is not unlikely that additional downward flexibility can be provided by the nuclear units.

**Conventional thermal units** are considered flexible and can deliver each type of flexibility when dispatched. The main constraint stems from the difference between the day-ahead schedule and their minimum stable power (downward flexibility) and the difference between the day-ahead schedule and the rated power (upward flexibility). However, most units require a start-up time and cannot deliver fast or ramping flexibility (i.e. old, recent and new CCGT) when not already dispatched. Other types such as new and existing OCGT, turbojets and diesel generators can deliver fast upward flexibility from standstill by means of a fast start-up time. The ramping flexibility is only provided by units which are effectively dispatched, and limited by the maximum ramp rate of the unit.

**Combined heat and power (CHP) units** are considered as two different types, i.e. 'individually modelled' and 'profiled'. The latter is considered must run and not considered as being able to participate in flexibility yet. The individually modelled type can be based on CCGT and OCGT units, which are assumed to have the same technical characteristics towards flexibility as if these would be CCGT or OCGT without CHP capabilities. Additional constraints are that these can only deliver downward flexibility (considered as must run) with an energy limit (considering that other processes cannot last a long time without steam). However, various applications exist for CHP and such a generalisation may be a simplification of reality.

- **Renewable generation**

When assessing variable renewable generation, the main contributor in Belgium today is **wind power.** It is generally considered to be able to provide downward flexibility (capabilities for upward flexibility are considered limited as their generation is driven by weather conditions), if they are equipped with appropriate communication and control capabilities. This is only the case for larger installations and this falls within their contractual obligations with Elia. It is assumed that these technologies will mainly provide fast and slow flexibility, although some units may also provide ramping flexibility if properly equipped.

The potential flexibility of wind power is capped to 65% of the scheduled output for offshore and 90% for onshore, based on the day-ahead forecast error (the capacity that is considered to be available in real time at least 99.0% of the time following a certain predicted capacity). While no further limits are assumed for fast and slow flexibility, it is assumed that part of the offshore wind power installations can provide up to 400 MW (18% of the current park) and up to 525 MW (through the Princess Elisabeth zone) of ramping flexibility. This value, representing 19% of the initially foreseen 2.1 GW, is extrapolated towards the current ambitions on offshore installed wind power of 3.5 GW. Note that also large **solar power** installations are assumed to contribute to downward flexibility. For this reason, this capacity is accounted, similar to onshore wind power, in fast and slow downward flexibility, by taking into account a cap set to 90% of the scheduled output.

In addition to variable renewable generation, biofuel units are assumed to provide all types of downward flexibility (assuming they are always scheduled at maximum power following generation support mechanisms). To provide downward flexibility, they are subject to the same type of technical constraints as conventional thermal units.

- **Technologies with energy limits**

**Batteries** (small-scale, also referred to as home batteries, large-scale and future vehicle-to-grid) and **pumped-hydro storage** are the most relevant storage technologies for Belgium. Large-scale batteries can deliver all types of flexibility in both directions without ramp rate limitations. This even means a potential inversion from full offtake to full injection. However, they do face an energy limitation depending on their energy storage capacity which is assumed to be limited at one hour generation or off-take at full capacity. Home batteries and future vehicle-to-grid is assumed to face an energy limitation of respectively 2 and 3 hours at full capacity. In contrast, while pumps and turbines in pumped-storage units can also deliver ramping flexibility, this is only assumed to be the case when the pump or turbine is dispatched. The energy limit is assumed to be 4.5 hours at full capacity.

**Electrolysers (power-to-gas technologies)** can in principle provide all types of flexibility if properly equipped for it. However, most value is expected to be held in long-term storage (e.g. seasonal) rather than in the intra-day and balancing time frame. For this reason, these units are only accounted as upward flexibility when being scheduled for gasification. In such cases, it is assumed that fast and slow upward flexibility increases can be delivered by reducing offtake without any technical constraints.

**Demand side response** (under the form consumption shifting and demand shedding) can also deliver ramping, fast and slow flexibility, typically only in an upward direction (reduction of consumption). The reaction times depend on the application. For the demand shedding applications, it is assumed that a total share of around 100%, 40% and 10% of installed market response can participate in respectively slow, fast and ramping flexibility. The energy limit is related to 5 categories (no limit, 1 hour, 2 hours, 4 hours and 5 hours). For consumption shifting, provided with 'smart' electric vehicle charging, it is assumed that these can deliver all types of upward flexibility with an energy limit of 8 hours at full capacity. For 'smart' heat pump consumption (by means of space or water heating), it is assumed that a total share of around 100%, 70% and 50% of installed market response can participate in respectively slow, fast and ramping flexibility. In addition an energy limit exists of a 5 hours for space heating and 7 hours at full capacity for water heating. This represents the total energy which can be activated throughout the day without comfort losses (and it is therefore not possible to activate respectively 5 to 7 hours in one time).

**Cross-border flexibility**

Cross-border flexibility is assumed to be constrained by the **remaining available interconnection capacity (ATC) after day-ahead trading**. This is estimated based on the hourly import/export schedule following the adequacy simulations, which are compared with a reference representing the maximum import/export schedules. Note that to simplify the process, this maximum is fixed at 7500 MW (import) and 8000 MW (export) for the investigated period between 2024 and 2034 but that in reality this value can vary on hourly basis.

Available cross-border flexibility also depends on the **liquidity in cross-border intra-day and balancing markets**. It is possible that not all required flexibility is available in other regions as this flexibility might also be constrained, or already used to deal with unforeseen variations in these countries. For slow flexibility, a liquid intra-day market is assumed and full capacity is taken into account, unless prices below 0 €/MWh and above 300 €/MWh indicated a regional excess or shortage (respectively), and limited the available capacity in intra-day and the balancing time frame.

For fast and ramping flexibility, the only cross-border flexibility currently in place or foreseen will go through FRR reserve sharing and imbalance netting (iGCC). As from 2022, the European balancing energy platforms will facilitate cross-border balancing energy exchange for aFRR and mFRR. Unfortunately, no estimations or projections are available on the expected liquidity on these balancing energy platforms and TSOs depend on a return on experience after implementation. This means that current 'firm' reserve sharing of 250 MW (upward fast flexibility) and 350 MW (downward fast flexibility), and 0 MW of iGCC (ramping flexibility) are the starting point for the analyses. These are complemented with sensitivities, e.g. where contribution increases to 50% and 100% of the needs. These assumptions and sensitivities may be calibrated based on available information on the go live of the EU balancing energy platforms on aFRR and mFRR.

Note that it is far from certain that the current cross-border capacities considered as 'firm' will increase, since optimisation of the grid use during day-ahead and intra-day may leave less capacity available for the balancing time.

## 4. 'CENTRAL' scenario and sensitivities

The **flexibility needs** will be analysed for 2024, 2026, 2028, 2030, 2032 and 2034. This included all assumptions for demand growth and the installed capacity of onshore and offshore wind, photovoltaics and must run generators. Also the installed thermal generation fleet, based on the existing and units planned to be constructed, contributing to the forced outages will be taken into account. Of course, the decision to enter or leave the market and the choice of technology and capacity is decided by the market and different scenarios will be analysed where relevant. To analyse the available **flexibility means**, the relevant years and scenarios from the above-mentioned selections will be investigated.