European Network of Transmission System Operators for Electricity

Public

UPDATED INPUT DATA AND ASSUMPTIONS FOR CBA LER ACCORDING TO ART.156(11) SO GL

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CONTENTS

Acronyms

ACE: Area Control Error

aFRR: automatic Frequency Restoration Reserve.

BSP: Balance Service Provider.

CBA: cost-benefit analysis.

CE NRAs: all the Continental Europe National Regulatory Authorities.

CE SA: Continental Europe Synchronous Area.

CE TSOs: all the Continental Europe Transmission System Operators.

FCR: frequency containment reserves.

FRP: Frequency Restoration Process.

FRR: Frequency Restoration Reserve.

ISP: Imbalance Settlement Period.

LER: providing units or groups with limited energy reservoirs.

LFC: Load Frequency Control.

MARI: Manually Activated Reserves Initiative.

PICASSO: Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation.

SOGL: Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation.

EES: Electricity Storage Systems

References

1. "All Continental Europe and Nordic TSOs' proposal for assumptions and a Cost Benefit Analysis methodology in accordance with Article 156(11) of the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation".

Executive Summary

According to Art.156(11) SO GL, CE TSOs shall develop a proposal concerning the minimum activation period to be ensured by FCR with Limited Energy Reservoir during alert state based on a Cost Benefit Analyses (CBA LER).

CE TSOs submitted their proposal based on the outcome of the CBA in December 2021. CE NRAs analysed the TSOs' proposal and issued in December 2022 a Request for Amendment of the proposal, asking a set of further analyses and a new run of the CBA methodology with updated input and assumptions.

This document is aimed at presenting this updated input and assumptions.

The document presents separately the three different types of input provided in the approved CBA methodology:

- Historical frequency data of CE SA.
- Outages on Generation Units and HVDCs.
- Costs of FCR for LER and non-LER.

Framework and scope of the document

Pursuant to Article 156(10) of the SOGL, CE TSOs shall develop a proposal concerning the minimum activation period to be ensured by FCR LER during alert state (hereinafter referred to as: proposal for Tmin LER definition). The proposal shall take full account of the results of the CBA conducted pursuant to Article 156(11) of SOGL. According to Article 6(3)(d)(v) of SOGL, the CE TSOs' proposal referred to in Article 156(10) of SOGL is subject to approval by CE NRAs.

CE NRAs approved the CBA methodology in October 2021 [1].

According to the CBA methodology, CE TSOs developed a probabilistic simulation model able to calculate the minimum amount of FCR needed to maintain the steady state frequency within maximum steady state frequency deviation. The CBA methodology provides for three different sources of frequency disturbance to be used as input by the probabilistic simulation model (Art.4.2 of [1]):

- Deterministic frequency deviation.
- Long-lasting frequency deviation.
- Outages of relevant grid elements.

Both deterministic and long-lasting frequency deviations must be derived from an analyses of frequency historical trend over several years.

Furthermore, the CBA methodology requires an assessment of cost of FCR (Art.5 of [1]). CE TSOs must define FCR cost curves which includes both LER and non-LER FCR providers.

This document is aimed at presenting updated assumptions regarding all the previous input.

The need for an update of all CBA input derives from an explicit request of CE NRAs. CE TSOs submitted indeed their proposal for the Tmin LER definition based on the outcome of the CBA in December 2021.

CE NRAs analysed the TSOs' proposal and issued in December 2022 a Request for Amendment of the proposal. In such Request for Amendment, CE NRAs request TSOs to run a new instance of the CBA methodology after having updated some of the key input regarding frequency and FCR costs.

For what regards the update of frequency input data, CE NRAs focused on the Long-Lasting Extraordinary Frequency Deviations events (hereafter referred to LLEFD).

LLEFDs are events where frequency constantly differs from the nominal value for a relatively long period of time (way more than the time to restore frequency, equal to 15 minutes for CE SA). The outcomes of the CBA have shown that the effects of LLEFDs play a key role in determining the Tmin LER.

According to the LFC scheme adopted in CE SA, any frequency deviation in the system should lead to a proper FRR activation which ensures the frequency to be restored within 15 minutes. As such, the presence of LLEFDs can be associated to an incorrect operation of the FRP.

To further investigate the issue, in 2022 CE TSOs have also performed and shared with CE NRAs a thorough root-causes analyses of the 20 most significant LLEFDs occurred between 2017 and 2021 in CE SA.

As part of their Request for Amendment, CE NRAs requested the TSOs to perform further analyses on the performances of the FRP and to present the measures CE TSOs are adopting to improve frequency quality by reducing the impact of LLEFDs.

CE TSOs performed the requested further analyses and presented the results to NRAs and to Stakeholders (in a dedicated workshop).

The updated assumptions about frequency deviation presented in this document take into consideration the outcomes of these further analyses.

For what regards the update of FCR costs, CE NRAs requested an update to consider the most recent development in LER technology and the evolution of the CE power system (for regards the costs of FCR from conventional non-LER providers).

Finally, this document also presents the main assumptions about outages. These assumptions are updated to take into account the most recent evolution in the CE power system.

Assumptions on input frequency data

Art. 4.2.a and Art.4.2.b of [1] requires the use of historical frequency data to derive the statistics regarding deterministic frequency deviations (DFDs) and long-lasting frequency deviations.

DFDs are the market-induced frequency deviations due to production variations between different markets' settlement periods.

Long-lasting Extraordinary frequency deviations (LLEFDs) are defined as event with an average steady state frequency deviation larger than the standard frequency deviation (±50 mHz) over a period longer than the time to restore frequency (15 minutes).

The use of historical frequency data for the CBA has been the chosen approach because it allows to consider the real frequency phenomena the FCR needs to address. The possibility of defining future frequency patterns and trends have been indeed deemed as an unfeasible solution, and then have been excluded after the consultation of the CBA, given the complexity of phenomena that can influence the frequency deviation at synchronous area level.

The historical frequency data to be used as input of the procedure need to be chosen considering two contrasting needs. On one hand, the period selected as input should be significant in terms of representativity of the system in the years to come. The use of very old frequency data could be misleading. On the other hand, the dataset should be long enough to represent a significant input for the probabilistic model used in the CBA. In this sense, several years of data are required to get reliable results from the probabilistic model.

CE TSOs have also considered to possibility of applying retroactive manipulations on older historical frequency data to make their frequency phenomena similar to those experienced by CE SA in the more recent years. This manipulation would specifically have regarded LLEFDs (most extraordinary LLFDs) which are one of the most impacting aspects on the CBA results. The less recent LLEFDs would have been manipulated - in terms of amplitude and duration - to make them resemble the LLEFDs occurred more recently. CE TSOs have indeed recently implemented several structural and operational countermeasures to mitigate LLEFDs.

However, such retroactive manipulation of historical frequency data it is not endorsed by CE TSOs for the reasons that will be better explained here below.

For one thing, every manipulation of historical frequency data is intrinsically an arbitrary operation. Each frequency event occurring on a synchronous area is the result of the combination of multiple different factors, all operating at the same time. To modify the trend of a specific historical frequency deviation would mean to deterministically suppose that - given the same combination of factors - the system would react today in a different way as it did in the past. Such supposition is very strong and it's not representative of how a synchronous area operates.

Furthermore, what is even more important is that the frequency trends in the last couple of years don’t show an improvement in terms of number and energetic content of LLEFDs. The events recorded in 2022-2023 resemble (in amplitude and duration) those occurred roughly ten years ago. Such worsening took place notwithstanding the mitigation measures put in place by CE TSOs.

CE TSOs consider the use of the last 10 years (2014-2023) the best compromise between having a significant amount of historical data and, at the same time, having a frequency behaviour that is representative of the present and coming years.

From the historical frequency dataset used as input of the CBA are excluded the events in which emergency state is triggered (e.g., separation of the CE power system on 8 January 2021).

Furthermore, frequency data below 48.5 Hz or above 51.5 Hz have been set equal to 50 Hz, because they likely are due bad quality data. In case of missing data, the frequency has been set equal to 50 Hz.

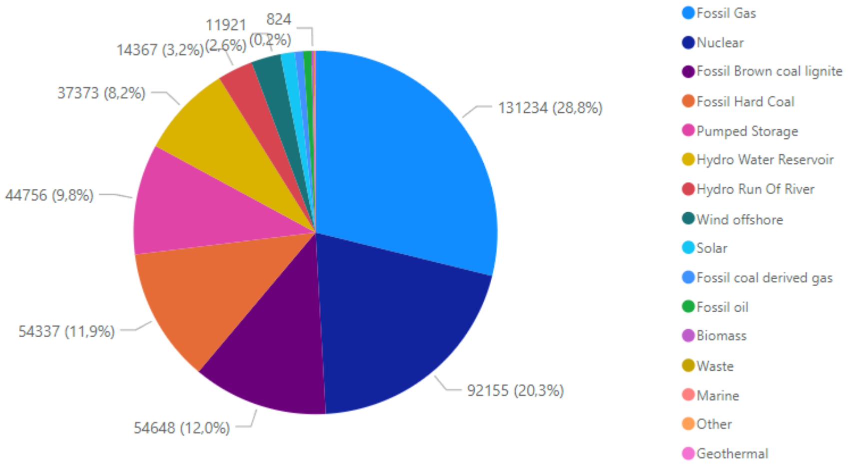
Assumptions and data sources for outages

Generation Units whose outages are considered

The set of potential plants whose outages are considered is derived from the Transparency Platform. On this source, only for plants having installed power greater than 100 MW outages statistics are present.

The table used for getting the installation plants is "Production and Generation Units", with the target year as reference year. The filter used on the table has the following criteria:

- Generation Unit Status = "Commissioned".
- GU Installed Capacity ≥ 100 MW.
- Production Type = All but "Wind Onshore".
- Validity: 01/01/2025 – 31/12/2025.



Technology	Installed capacity GU [MW]	Number of units	Average installed capacity [MW]	Max inst. capacity [MW]
Fossil Gas	131.234,30	393	333,93	1.304,00
Nuclear	92.154,80	105	877,66	1.500,00
Fossil Brown coal lignite	54.647,50	171	319,58	1.060,00
Fossil Hard Coal	54.337,00	164	331,32	1.075,00
Pumped Storage	44.755,90	203	220,47	1.307,00
Hydro Water Reservoir	37.373,40	185	202,02	1.870,70
Hydro Run Of River	14.366,50	76	189,03	737,00
Wind offshore	11.920,80	42	283,83	600,00
Solar	5.801,10	28	207,18	605,90
Fossil coal derived gas	3.377,60	12	281,47	590,00
Fossil oil	3.318,90	19	174,68	372,90
Biomass	824,00	4	206,00	268,00
Waste	298,10	2	149,05	189,10
Marine	240,00	1	240,00	240,00
Other	149,00	1	149,00	149,00
Geothermal	114,00	1	114,00	114,00
Totale	**454.912,90**	**1407**	**323,32**	**1.870,70**

Figure 1: Example of 2024 relevant units for outages (to be updated with 2025 as target year).

Outages on wind onshore units are not considered since their most likely outages don't result in the complete and sudden loss of their injection at the point of connection but rather in the loss of some wind turbines.

For nuclear and coal plants "partial outages" are also considered. partial outages are events in which a unit undergoes a rapid but partial loss of power output (without disconnecting from the system).

Outages on load side are not considered. Their potential impact in terms of power imbalance at synchronous area level can be neglected.

Power loss associated to an outage of a Generation Unit

To each outage a power loss shall be associated. Should the outage occur, this power is the unbalance the system must cope with by using FCR and FRR.

The simulation model does not provide the possibility to simulate the actual power output of each Unit according to market results: no market solution is calculated; all the plants are considered always in service (and therefore always subject to the possibility to undergo an outage).

When an outage on a production unit occurs, the power imbalance caused to the system is thus calculated considering the installed power and a load factor differentiated for technology:

$$P = P_{inst} \cdot Load\ Factor$$

Where:

P_{inst} is the unit's installed power derived from ENTSO-e Transparency Platform table "Production and generation units", field "GU InstalledCapacity".

$$Load\ Factor = \frac{\sum_{h=1}^{h=8760} (Actual\ Generation\ per\ Production\ Type)_{h,i}}{(Installed\ Capacity\ per\ Production\ Type)_i},\ \ \forall\ technology\ i$$

The Load Factor for offshore units is not derived from ENTSO-e Transparency Platform. CE TSOs deem as more reliable the use of literature data[1]. The load factor is set in this case to 45%.

[1] *Source: "FUTURE OF WIND - Deployment, investment, technology, grid integration and socio-economic aspects.", IRENA 2019.*

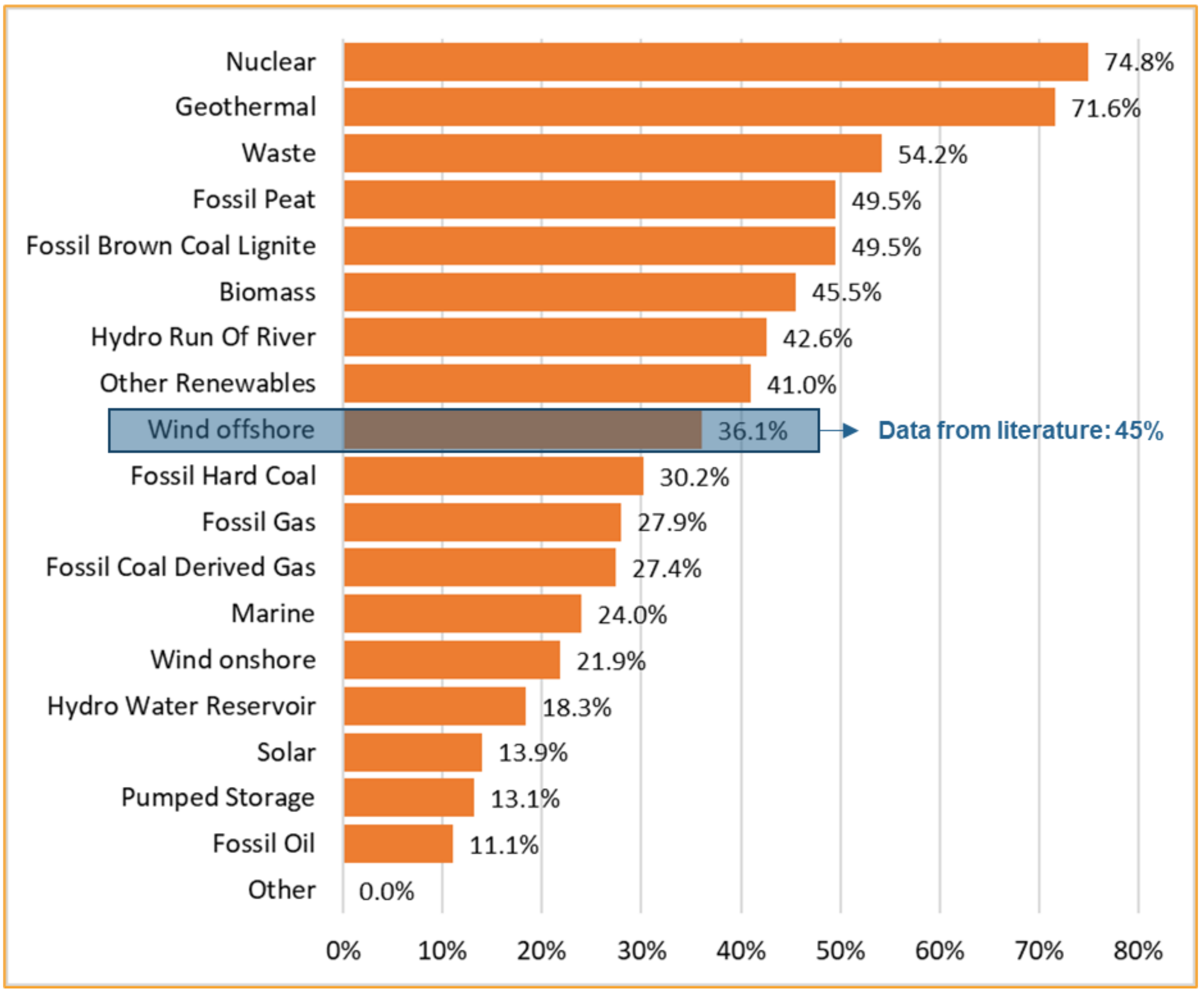


Figure 2: Example of Load Factor for the calculation of the power loss due to outages (from 2021 TP data).

Partial outages

To define which technologies are more likely to undergo a partial outage, an analysis on outages recorded on the ENTSO-e Transparency Platform has been carried out. The tables used for collecting the outages are “Unavailability of Production and generation Units.

Analyzing the recorded events on the Transparency Platform, it is possible to calculate the ratio between the number of partial outages[2] and the total number of events.

According to these results, the only technologies for which the partial outages are considered are:

- Fossil Coal-derived gas.
- Nuclear.

[2] *A partial event is defined as an event in which the power loss is less than half the installed power.*

- Fossil Hard coal.
- Fossil Brown coal/Lignite.

The power loss to be associated with partial events is derived from the Transparency Platform and it is calculated as the average power loss of partial events.

Probability of occurrence of outages of a power Generation Unit

To each outage shall be associated a probability of occurrence. This probability is exploited by the probabilistic model to randomly extract an outage with the correct rate.

The failure rates for outages on thermoelectric and hydroelectric units are derived from literature[3]. They are presented in the following Table 1.

Table 1 - Failure rate from literature for thermoelectric units (failure rate on hydro units is assumed equal to gas turbines).

	Fossil-fired			Combined Cycle	Gas Turbine	Nuclear
	Hard coal	Lignite	Gas/oil			
Average failure rate [n°events/unit/year]*	**7.92**			**6.62**	**0.88**	**1.2**
Number of surveyed units	181			53	42	20
Surveyed years	2008-2017					

The failure rate for offshore wind farms is derived from literature regarding the North Sea plants and it accounts only for the failures on the connection between the wind farm and the shore. An average failure rate of 0.005 failure/km/year is assumed. An average distance of 75 km is assumed between the wind farm and the connection point on the shore.

For utility scale PV plants (installed power higher than 100 MW), the failure rate is derived from literature and it's equal to 1.02 event/year.

Partial outages

The rate at which partial outages occur is derived from an analysis of ENTSO-e Transparency platform data. Analysing the recorded events is possible to calculate the number of partial events occurred in each year for each technology:

$$FailureRate_{y,t} = \frac{number\ of\ events_{y,t}}{number\ plants\ in\ operation_{y,t}}$$

For each technology *t* and each year *y*.

The probability of occurrence to be used is the yearly average value:

[3] *"Analysis of Unavailability of Power Plants 2008 – 2017", VGB report for hydroelectric and thermoelectric technologies.*
The kind of outages relevant for CBA are those occurring within a very short time frame (thereby causing a power unbalance in the power system). The data considered as failure rates are therefore taken from §B.4 (Time frame) for the categories A and B ("Automatic and Manual load-rejection/fast shutdown"). The failure rates of full outages on hydro power units have been assumed to be equal to the failure rate of Gas Turbine: 0.88 event/year/unit

$$PartialOutageProbabilityOfOccurrence_t = \frac{1}{number\ of\ years}\sum_{y} FailureRate_{y,t}$$

Statistic of HVDC outages

The HVDCs whose outages can affect the frequency deviation are those which connect different SAs. In the CBA are then considered only the HVDC connections in service at the target year where only one of the ends belongs to the CE SA.

Table 2: Example of HVDC links in service in 2024 (to be updated with 2025 as target year).

Name	Power [MW]	Zone From	Zone To	Status
IFA 1	-2000	FR00	UK00	In service
BritNed	-1000	NL00	UK00	In service
NorNed	-700	NL00	NOS0	In service
Skagerrak 1_2	-250	DKW1	NOS0	In service
Skagerrak 3	-1000	DKW1	NOS0	In service
Skagerrak 4	-700	DKW1	NOS0	In service
Konti-Skan 1	-250	DKW1	SE03	In service
Konti-Skan 2	-300	DKW1	SE03	In service
StoreBaelt	600	DKE1	DKW1	In service
Kontek	-600	DE00	DKE1	In service
Baltic Cable	-600	DE00	SE04	In service
SwePol	-600	PL00	SE04	In service
Nemo	-1000	BE00	UK00	In service
IFA 2	-1000	FR00	UK00	In service
ElecLink	-1000	FR00	UK00	In service
Viking Link	-1400	DKW1	UK00	In service in 2023
Kriegers Flak CGS	-400	DE00	DKE1	In service
NordLink	-1400	DE00	NOS0	In service
COMETA	400	XMA00	ES00	In service
SAPEI	-1000	ITCS	ITSA	In service

Colour legend
Connections to UK or IE
Connections to Nordic
Connections to other non-synch. areas

The direction and power loss associated with the outage on a HVDC link depends on the hour at which the event occurs. The value is based on historical flows derived from ENTSO-e Transparency Platform according to the following formulation:

$$P_{Loss,h} = min\left(max\left(0.5 * P_{HVDC},\ \left|Flow_{h,\,A\leftrightarrow B}\right| / n_{interconn,\,A\leftrightarrow B}\right), P_{HVDC}\right)$$

Where:

P_{HVDC} is the installed power of the HVDC.

$Flow_{h,\,A\leftrightarrow B}$ is the flow in the hour h between the area A and area B, according to ENTSO-e Transparency Platform data.

$n_{interconn,\,A\leftrightarrow B}$ is the number of HVDC connecting area A and area B:

- if data historical flow data are available for the single HVDC, this parameter is equal to one).
- if data historical data are available only for the inter-area flows this parameter is equal to the number of HVDCs connecting the two areas.

Failure rates for HVDC are based on the document "ENTSO-E HVDC Utilization and Unavailability Statistics 2020", 24 June 2021. The source presents 2012-2020 statistics for Baltic/Nordic HVDCs.

On average 3.5 outages/year occur.

If a connection is present in the ENTSO-e report, its outage/year statistic is used as failure rate. If a connection is not present in the ENTSO-e report, the average outage/year statistic is used as failure rate. The results are presented in the following Table 3.

Table 3: Failure rate for HVDC links.

HVDC	Failure rate [event/year]
IFA 1	3.48
BritNed	3.48
NorNed	3.11
Skagerrak 1_2	4.22
Skagerrak 3	2.33
Skagerrak 4	3.50
Konti-Skan 1	5.44
Konti-Skan 2	6.22
StoreBaelt	1.22
Kontek	1.22
Kriegers Flak CGS	3.48
Baltic Cable	3.67
SwePol	4.67
Nemo	3.48
IFA 2	3.48
ElecLink	3.48
Viking Link	3.48
NordLink	3.48
COMETA	3.48
SAPEI	3.48

Assumptions on FCR costs for LER and non-LER

For both LER and non-LER resources 2025 is chosen as reference year for the analysis. This means that the FCR supply curves resulting from the data collection and analysis activities detailed in this section refer to year 2025.

The choice of the reference year affects aspects like the costs, the installed capacity per technology and other parameters needed for the analysis.

2025 has been selected as reference year for the cost analysis since a short-term time horizon allows to limit the high level of uncertainty about the expected technological and costs evolution.

Specifically, 2025 is proposed as the reference year both for LER and non-LER resources considering the following:

- For non-LER recent historical spot prices are used as the main source for scenario data, The assumption is a price stability in the near term (after the pandemic and Ukraine war market shocks). These historical spot prices:
  - refer to the same period (November 2022 – October 2023).
  - are gathered from publicly available sources.
- For new LER specifically commissioned for FCR provision 2025 is considered as the investment year.
- The resulting FCR cost curves refer to year 2025
- All costs/prices are expressed in real terms in € 2023. Official BCE yearly average exchange rates[4] and official IMF inflation rates[5] have been used whenever needed.

LER resources for FCR provision

In principle, several technologies for electricity storage systems (EESs) are possible for FCR provision.

To select which specific systems/technologies are to be included in the LER for FRC provision cost analysis, there are different aspects to be considered:

- ESSs can potentially provide a wide range of services for the power system, including primary, secondary, and tertiary frequency regulation. Different technologies are however better suited (or mainly used) for specific applications.
- Different ESSs and specific technologies have different costs and are in different stages of their technological maturity. The selection of specific ESSs/technologies varies therefore according to the target year (near term vs long term).

[4] *ECB Statistical Data Warehouse, http://sdw.ecb.europa.eu/browse.do?node=9691296*
[5] *IEA, April 2019, https://www.imf.org/external/datamapper/PCPIPCH@WEO/OEMDC/EUQ*

Following a thorough data and information research based on publicly available sources[6], it resulted that currently lithium-based battery technology (Li-ion batteries) is the better suited solution for LER for FCR provision in the near term.

Three different categories of LER for FCR provision are considered:

- New LER dedicated to FCR provision.
- Existing LER.
- New LER not specifically commissioned for FCR provision.

The following sections focus on each category.

[6] *International organizations, consultancy and research firms, universities and academic literature, press releases from various stakeholders, specialized magazines, etc.*

New LER dedicated to FCR provision

The new LER dedicated to FCR provision category is the most relevant in terms of volumes in the context of the parametric analysis to be performed for the CBA, and the most complex in terms of data collection and analysis.

For new LER specifically commissioned for FCR provision the cost curve definition is based on the Long-Run Marginal Cost concept, where all production factors are endogenous, including the Investment cost (CAPEX) and the Yearly fixed Operation and Maintenance costs (OPEX), as detailed in Figure 6.

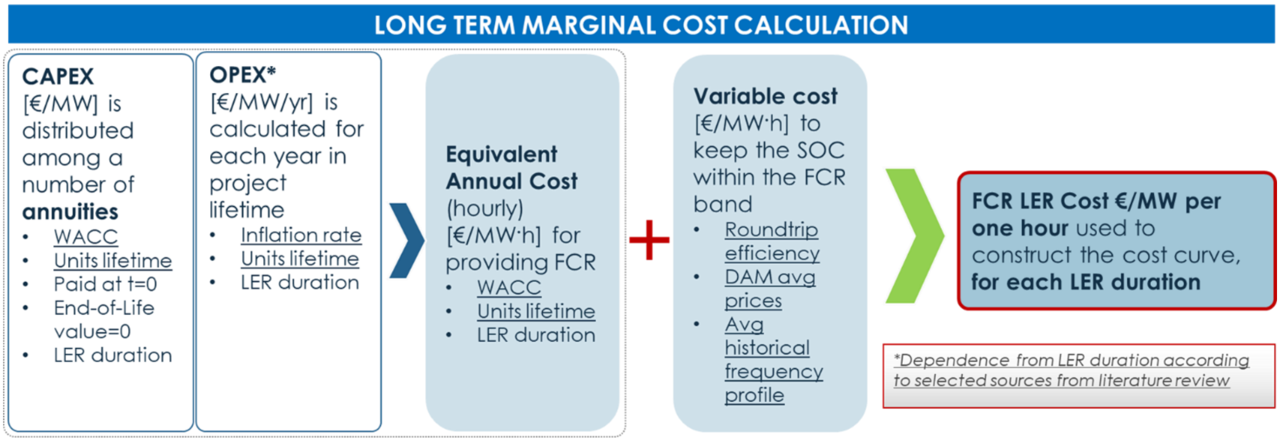


Figure 3: Long term marginal cost calculation for new LER dedicated to FCR. Source: literature review and CESI's analysis.

CE TSOs conducted an extensive data collection, with the target of creating a database with all the data and information needed for the cost analysis.

The main sources analyzed and exploited for the costs assessment are:

- IRENA – “Electricity storage evaluation framework: assessing system value and ensuring project viability” (2020)
- IEA – “World Energy Investment 2023”
- LAZARD – “Levelised Cost of Storage Analysis – Version 7.0” (April 2023)
- U.S. EIA – “Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies” – (2020)
- U.S NREL – “Storage future study-Storage Technology Modelling Input Data Report” – (2022)
- U.S NREL – “Storage future study-key learnings for the coming decades” – (2022)
- U.S NREL– “Utility Scale BESS 2022 Annual Technology Baseline” – (2022)
- U.S. NREL and Sandia National Laboratories– “2019 Energy Storage Pricing Survey” – (2021)
- U.S DOE Pacific Northwest National Laboratory – “2022 Grid Energy Storage Technology Cost and Performance Assessment” (2022)
- U.S. Department of Energy - Global Energy Storage Database - https://energystorageexchange.org/
- Energy Transition Expertise Centre for European Commission – “Study on Energy Storage” (2023)
- Joint Research Centre EU (JRC) – Batteries for energy storage in the European union (2022)
- Journal of Energy Storage – “The development of stationary battery storage systems in Germany –A market review” (2020)
- Energy & Strategy Group (Polytechnic University of Milan) – “Energy Market Report” – (2022)
- The European Association for Storage of Energy (EASE)
- Press releases and other documents from different stakeholders on specific projects

The data collection activity for CAPEX (€/kW – total installed cost) has been pursued taking into due account the importance of all the key aspects needed to construct the LER cost curves:

- the specific technology considered.
- the size cluster (MW of installed power) of interest.
- the LER duration (Energy to Power – E/P – ratio).
- the investment/commissioning year.

According to the data collected, a regression analysis (based on data from 50 projects/cases) is performed to estimate the relation between the duration (E/P ratio - independent variable) and the investment cost (€/kW – dependent variable) of Li-ion batteries.

The resulting linear equation is used to estimate the current CAPEX for the different target durations. The original data refer to projects/costs from different reference years, and for consistently performing the regression analysis all costs have been reported to the target year 2025 (in real € 2023 terms) based on the NREL study on costs evolution data.

Target durations need to be over-dimensioned to guarantee minimum duration requirements all over the lifetime of the system due to degradation and dept of discharge parameter. Therefore, the costs analysis included an expected energy capacity degradation of the battery during the lifetime of the project. The degradation implies that, at the end of its lifetime, the battery energy capacity will be reduced compared to the nominal value. A higher upfront investment in energy capacity allows to ensure the required duration all over the life of the project.

According to the literature review, batteries degradation has two dimensions:

- calendar ageing.
- cycle ageing.

This means that the total degradation depends on the total lifetime of the project (the longer the life, the higher the total degradation) and on the way the battery is used (charge and discharge cycles).

Lifetime of the Li-ion battery energy storage systems have been assumed equals to 15 years. The calculation of the total battery degradation (due to both calendar and cycle aging) has been based on academic studies.

Figure 8 summarises how the battery degradation has been included and treated in the analysis.

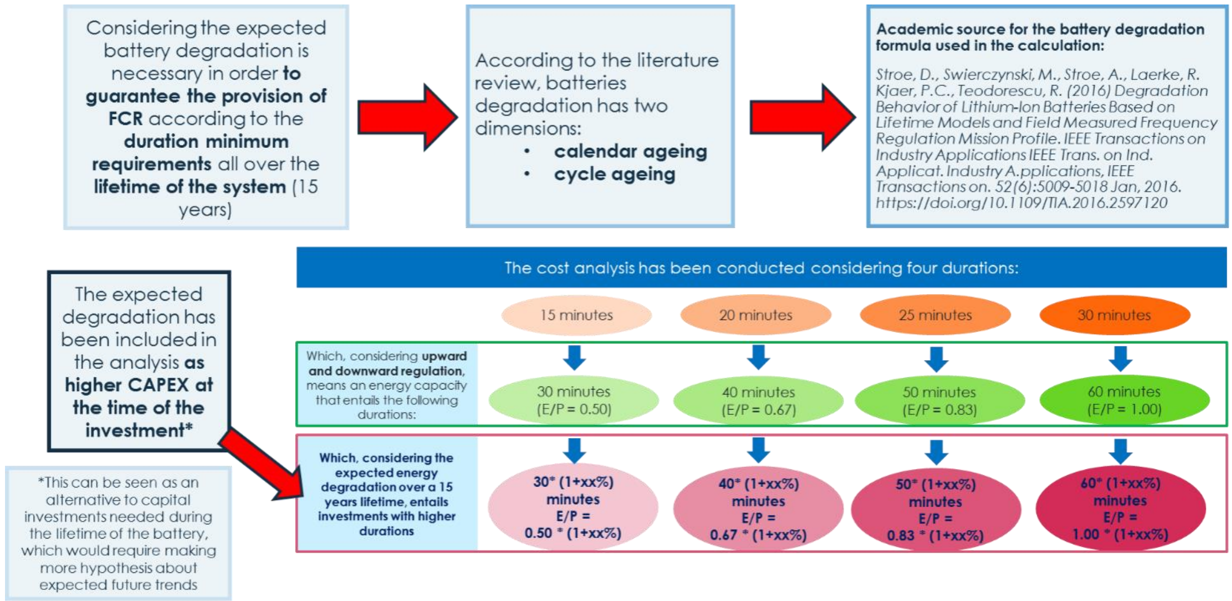


Figure 4: Duration of the Li-ion battery systems considering the degradation over the lifetime. Source: based on the literature review and data collection activity.

According to the literature, the Depth of Discharge (DoD) is another technical specification of the batteries that needs to be considered for the costs calculations. Batteries have a maximum allowed discharge rate which defines the actually usable energy capacity (kWh) of the battery. In line with the degradation, this parameter entails an over-dimensioning of the system at the time of the investment, to guarantee the provision of FCR according to the time period required. Following an internal discussion with the CBA working group and based on some literature sources, the DoD has been set equal to 90% for the purposes of the current analysis.

10 MW has been chosen as reference size for the costs analysis. Systems with much bigger or smaller sizes have not been considered for the analysis.

Only projects commissioned in the last few years have been considered, since due the significant technological/costs improvements happened in the recent past, data from older projects could be difficult to compare with more recent installations.

Based on the collected data of different Li-ion battery projects with similar sizes, commissioned in the last few years, the regression analysis has been performed to estimate the relation between the duration (E/P ratio – independent variable) and the cost (CAPEX, €/kW of installed capacity – dependent variable). Figure 8 shows the regression analysis with the resulting linear equation.

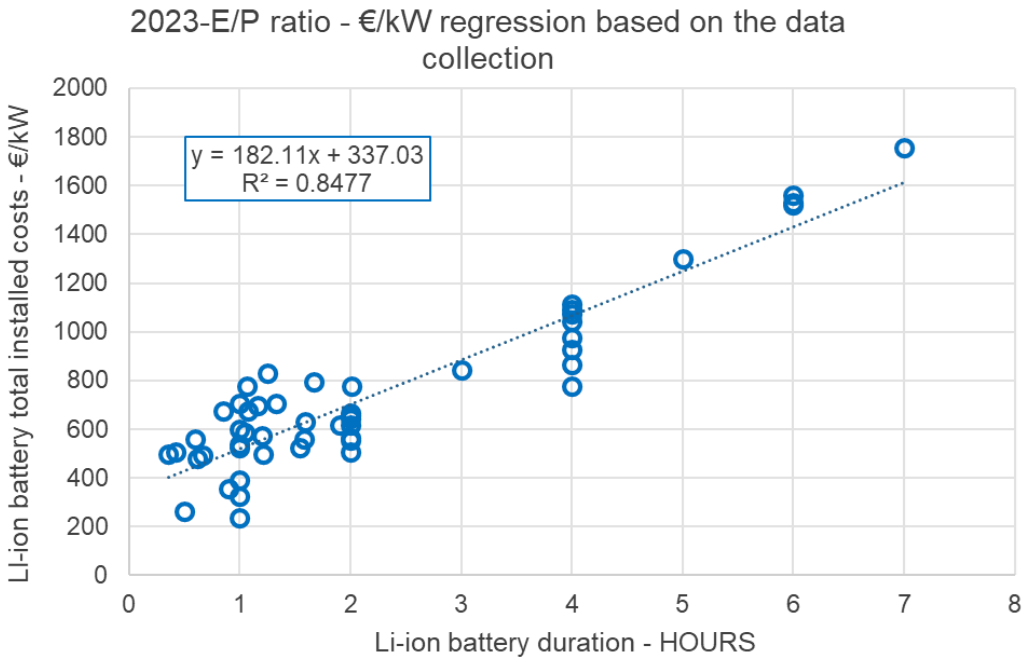


Figure 5: Regressions analysis for Li-ion batteries duration and costs. Source: based on the literature review and data collection activity.

Figure 9 shows CAPEX values in €/kW resulting from applying the linear equation of the regression to the target durations – including the DoD and the expected degradation.

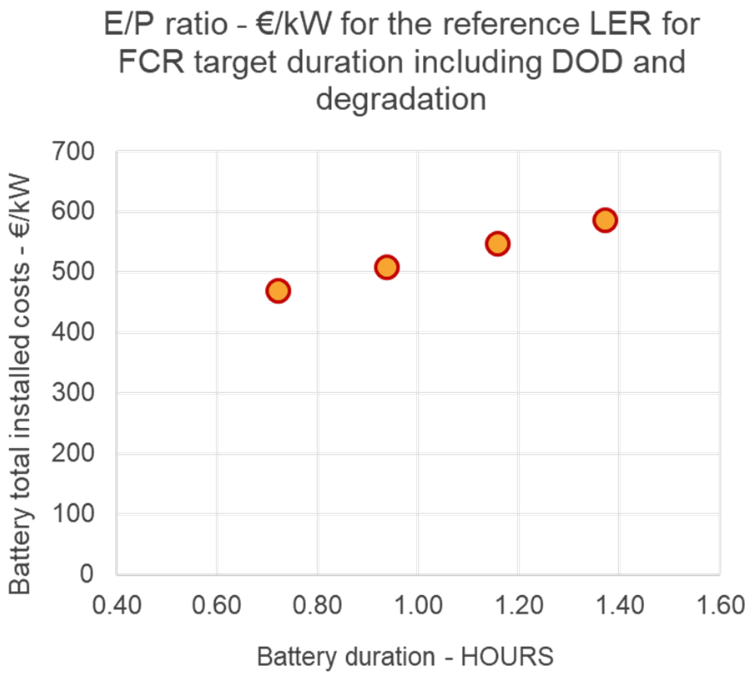


Figure 6: CAPEX for Li-ion batteries with target durations. Source: based on the literature review and data collection activity.

To calculate the Long Run Marginal Cost a few other parameters are needed:

- The discount rate, or the weighted average cost of capital (WACC).
- Yearly fixed Operation and Maintenance costs (OPEX), in €/MW/year.
- Variable energy costs (€/MWh per 1 MW).

For the discount rate it has been used a real rate of 4%.

OPEX (Operation and maintenance, O&M) costs include all costs needed to keep storage equipment operating. Fixed O&M costs include all necessary costs that are not based on usage (i.e., costs that need to be paid no matter what the use case is) but exclude cost of augmenting storage system due to degradation.

Fixed OPEX are based on data from the 2022 study of the U.S. DOE Pacific Northwest National Laboratory “2022 Grid Energy Storage Technology Cost and Performance Assessment”, which have been used as the base for a regression analysis, which is reported in Figure 10.

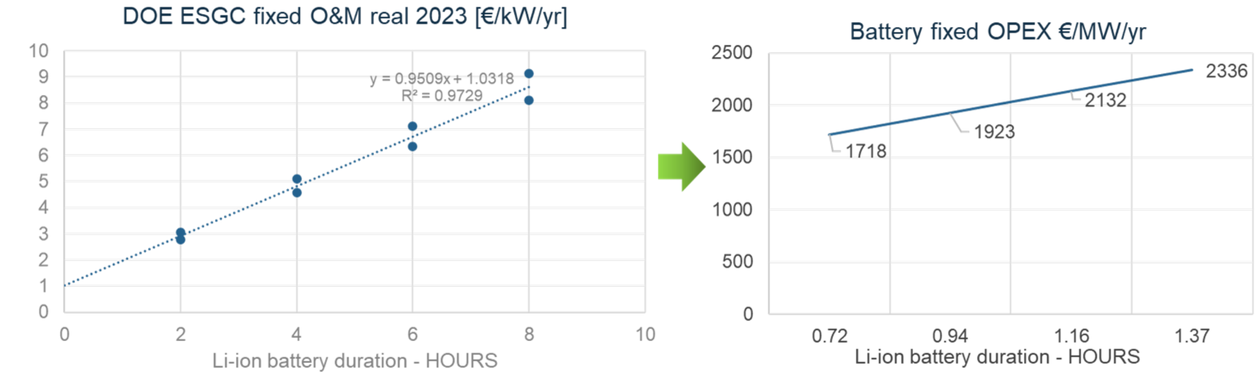


Figure 7: OPEX for Li-ion batteries – regression analysis. Source: CESI's elaborations on U.S. DOE data.

Variable O&M cost is calculated as the charging cost to keep the state of charge (SOC) of the battery within the FCR band. Such costs depend on:

- Day Ahead Market (DAM) prices.
- round-trip efficiency (assumed to be 86%).
- The charging/discharging volumes. They depend on the actual FCR activation calculated from historical frequency data.

For each duration, the specific investment cost, €/MW of one benchmark unit, is distributed among the annuities of the project lifetime. The cost (in €/MW) per one hour is then calculated and used to build the cost curve. Figure 11 summarizes the parameters used for the analysis and the results of the regression and the final FCR provision cost for Li-ion batteries.

Main inputs/assumptions - CE	Technology	Reference year	Project lifetime	Discount rate	Battery size	fixed OPEX (nominal value)	Round trip efficiency	Variable energy costs CE	Depth of Discharge - DoD	Battery energy capacity degradation over 15 years - CE	Final battery investment overdimesioning (including DoD + degradation) - CE
		year	years	%	MW	€/MW/Y	%	€/MW(h)	%	%	%
Parameter value - Tmin LER 15 mins	Li-ion Battery	2025	15	4.0%	30	1718	86.0%	0.62	90.0%	23.0%	44%
Parameter value - Tmin LER 20 mins	Li-ion Battery	2025	15	4.0%	30	1923	86.0%	0.62	90.0%	21.0%	41%
Parameter value - Tmin LER 25 mins	Li-ion Battery	2025	15	4.0%	30	2132	86.0%	0.62	90.0%	20.0%	39%
Parameter value - Tmin LER 30 mins	Li-ion Battery	2025	15	4.0%	30	2336	86.0%	0.62	90.0%	19.0%	37%

Regression analysis results for the target Tmin LER - CE	Duration - nominal	Duration - actual, for CAPEX calculation (including DoD & degradation)	CAPEX
	Hours	Hours	€/kW
Tmin LER 15 mins	0.50	0.72	468
Tmin LER 20 mins	0.67	0.94	508
Tmin LER 25 mins	0.83	1.16	548
Tmin LER 30 mins	1.00	1.37	587

- To calculate the variable costs for providing FCR it has been taken as a reference a round-trip-efficiency 86%.
- For volumes and costs, the calculation has been based on average historical frequency profiles and on average DAM prices Nov22-Oct23

Li-ion batteries FCR provision cost (long run marginal cost) - CE	FCR cost CAPEX + OPEX	FCR cost total (CAPEX, OPEX, energy) - CE
	€/MW(h)	€/MW(h)
Tmin LER 15 mins	5.05	5.67
Tmin LER 20 mins	5.49	6.11
Tmin LER 25 mins	5.93	6.55
Tmin LER 30 mins	6.36	6.98

- ✓ For each duration, the specific investment cost, €/MW of benchmark unit, and fixed O&M €/MW/yr are distributed among a number of annuities according to the project lifetime
- ✓ The equivalent annual cost €/MW per hour of benchmark unit for providing FCR is calculated
- ✓ Then the cost €/MW per one hour is calculated including charging cost and used to construct the cost curve.

Figure 8: Main parameters and results of the regression and costs analysis for Li-ion batteries for FCR provision – CE synchronous area. Source: based on the literature review and data collection activity.

Existing LER

For the cost of FCR for existing LER, the following considerations apply:

- CAPEX costs are considered as sunk costs and are therefore neglected.
- Over-dimensioning costs (for degradation and DoD) are not relevant since they are included in the CAPEX.
- Opportunity costs related to other services (alternative to FCR), that can be provided by the LER, are not included in the analysis, since they entail complex and very case-specific strategies.
- Variable costs associated with energy costs to compensate for round trip efficiency are considered. They are calculated in the same way as for new LER, considering:
  - Day Ahead Market (DAM) prices.
  - round-trip efficiency (assumed to be 86%).
  - The charging/discharging volumes. They depend on the actual FCR activation calculated from historical frequency data.
- OPEX costs (Operation and maintenance) are considered. They are calculated in the same way as for new LER.

To summarise, variable energy costs and OPEX are the only costs associated to existing LER.

The existing LER which are not batteries (namely run-of-river hydro plants with limited water reservoir) are considered in the same way as non-LER. Their FCR cost is based on the opportunity cost of providing FCR instead of operating on energy markets.

The quantities of available FCR from existing LER is derived from a survey performed amongst CE TSOs. The survey is aimed at defining the prequalified values of FCR from LER in each LFC Block. In the survey the quantities pre-qualified for different minimum activation time periods are differentiated.

New LER non-specifically commissioned for FCR provision

The possibility of provision of FCR by LER as one of several sources of revenue (revenue stacking) is neglected in the study. In this sense, the opportunity costs for LER of offering other ancillary services and/or arbitrating on DAM/IDM are neglected.

The study is indirectly aimed at understanding the profitability of installing new batteries for FCR provision. It is therefore reasonable to consider new LER installation as solely dedicated to FCR provision and to consider their FCR cost in terms of long run marginal costs.

FCR can also be provided by limited energy resources which are not specifically commissioned for the ancillary services provision. For this kind of providers, the FCR would represent a secondary source of revenue. Typical examples in this sense are electric vehicles or heat pumps.

These kinds of providers are however expected to play a very minor role in terms of quantity by 2025 and are therefore neglected in the study.

Non-LER resources

For non-LER resources the key sources of costs data are the historical spot prices, since after the pandemic market storm and the peaks that followed also due to the Ukrainian war, the assumption and expectations is of costs/prices for the near future in line with the recent past.

The key sources for data and information are the following:

- ENTSO-E transparency platform
  - Historical DAM prices November 2022 – October 2023
- Nordpool
  - Historical DAM prices November 2022 – October 2023 for France
- World Bank Commodities Price Data (The Pink Sheet), November 2, 2023
  - Historical Fuel prices November 2022 – October 2023
    - Coal
    - Brent
    - Natural gas
- US EIA 2022 - ENTSO-E TYNDP24
  - Nuclear fuel price 2022 (US EIA is the primary source, adopted as reference for TYNDP24 long term scenarios)
- EEX Emissions market / Primary Market Auction
  - EUA primary auction results November 2022 – October 2023
- ENTSO-E TYNDP20
  - efficiencies, emissions factors, variable O&M costs
  - available capacity per technology per country for 2025 scenario
- ENTSO-E transparency platform for further data needed for pumped hydro resources
  - Current (2022-2023) installed pumped-hydro capacity per country
  - Current (2022-2023) actual hourly generation per technology (type) per country

All historical spot prices data refer to the same period, November 22 – October 23[7], and they are all from publicly available and referenced sources.

FCR volumes for each country and each non-LER technology are derived from a survey amongst CE TSOs.

[7] *Apart from nuclear fuel price, which refers to 2022 but comes from a referenced and up-to-date source and used as a reference by ENTSO-E for the long-term scenarios. November 2022 – October 2023 it the last full year (12 consecutive months) of data available at the time of performing the analysis.*

For non-LER resources the cost for providing FCR is based on the opportunity costs calculation, where the alternative opportunity is based on the DAM market prices. This approach is summarised in Figure 12.

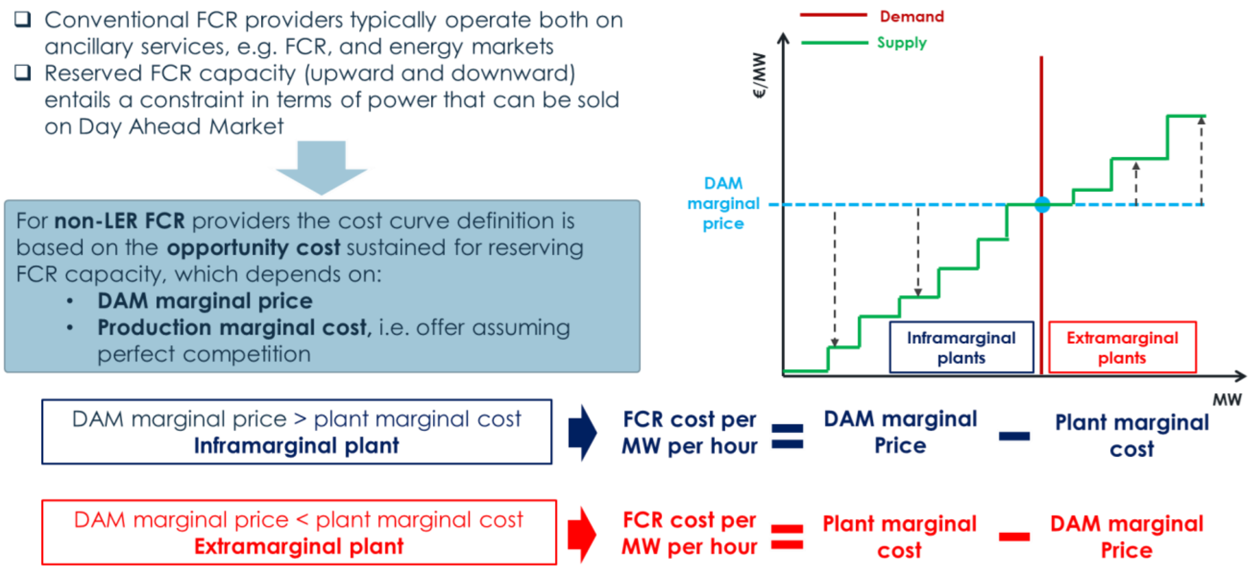


Figure 9: Opportunity cost for FCR provision for non-LER generators. Source: CESI elaborations.

Hydro resources

For non-pumped hydro resources, similarly to other renewables, the variable cost (costs of water) is equal to zero, so that the opportunity cost for providing FCR is equal to the system marginal cost.

Pumped-hydro resources require some more elaborations and assumptions to calculate the opportunity costs. In general, similarly to thermal power plants, they have a variable cost which is equal to the price of electricity for pumping water (when they work in pumping mode) divided by the efficiency.

Such costs depend on the DAM price differentials that pumped hydro plants can take advantage from. A study has been conducted to derive such differentials from ENTSO-e Transparency Platform data.

Once *fuel-like* (variable) costs of pumped hydro plant are estimated, the opportunity cost of providing FCR is calculated in the same way as for thermal power plants.