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Harmonised system-wide cost-benefit analysis for candidate energy storage projects

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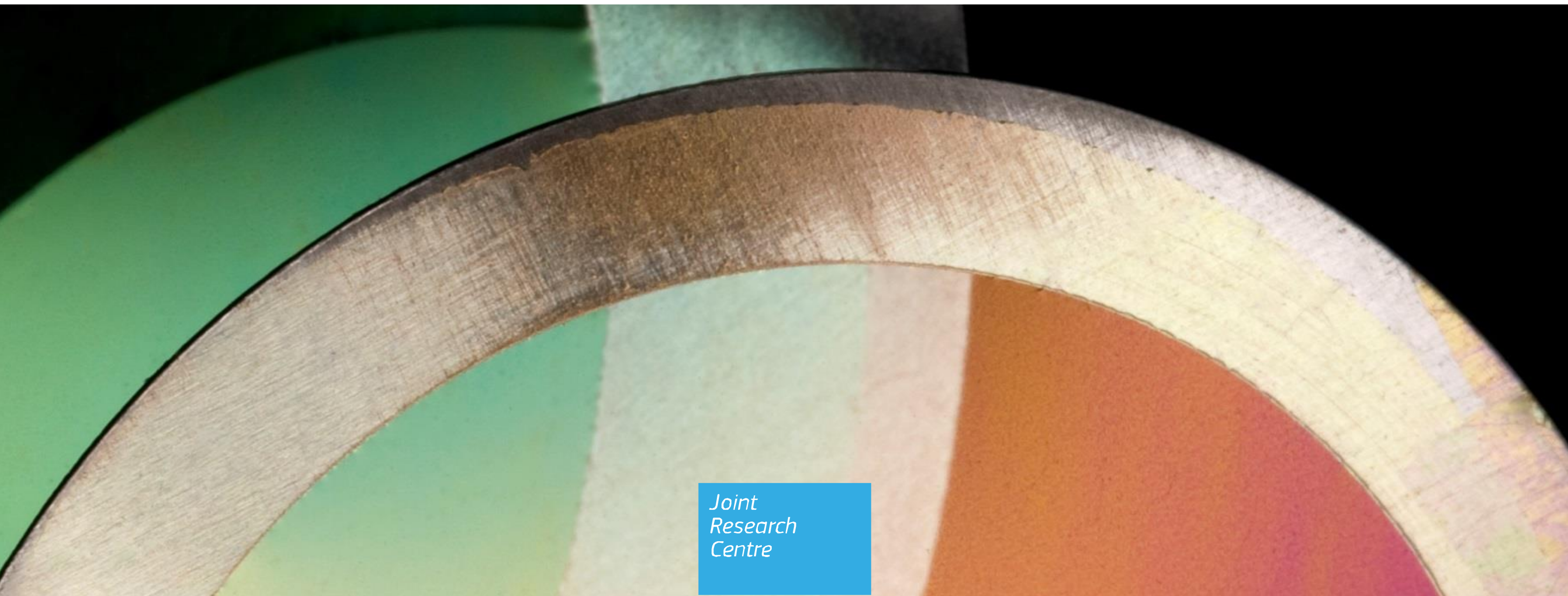

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Abstract

This report presents the developed Cost-Benefit Analysis (CBA) methodology for candidate energy storage projects, in compliance with the requirements set in the Regulation (EU) 2022/869. The current methodology shall be used for candidate PCI energy storage project appraisals and provides for a societal CBA with the use of monetised, quantified and qualitative indicators. Taking account of the Guidelines for CBA of Grid Development Projects, the methodology is designed to be compatible in terms of benefits and costs with the CBA methodologies developed by the ENTSO-E.

Executive summary

Recognising the importance of energy storage, the revised TEN-E Regulation (Regulation (EU) 2022/869) includes energy storage facilities as energy infrastructure category. Energy storage facilities can be in individual or aggregated form, used for storing energy on a permanent or temporary basis, in aboveground or underground infrastructure or geological sites, provided they are directly connected to high-voltage transmission lines and distribution lines designed for a voltage of 110 kV or more. For Member States and small isolated systems with a lower voltage overall transmission system, those voltage thresholds are equal to the highest voltage level in their respective electricity systems.

In this context, the JRC, in compliance with the requirements set in TEN-E Regulation, has developed a dedicated societal Cost-Benefit Analysis (CBA) methodology for candidate energy storage projects to be included in the list of Projects of Common Interest (PCIs). The current methodology provides for an analysis, utilising monetised, quantified and qualitative indicators. This CBA methodology will feed into the assessment of candidate PCI energy storage projects to assess whether their potential overall benefits outweigh their costs.

This methodology has identified the main benefits of energy storage in accordance with the specific criteria of sustainability, market integration, and security of supply in the revised TEN-E Regulation. Specific monetised, quantified and qualitative indicators have been developed for the assessment of these benefits that can be summarised in ten main categories:

- Variation of socio-economic welfare in electricity markets
- Variation of GHG emissions
- Variation in curtailment of electricity from Renewable Energy Sources
- Variation of non-CO_2 emissions
- Variation in grid losses
- Variation in electricity balancing markets
- Variation in other ancillary services markets
- Adequacy to meet demand
- Generation capacity deferral
- Transmission capacity deferral

The methods to quantify and monetise such benefits are described for cases with and without detailed modelling instruments available. Key parameters for quantification are presented, with potential data sources.

1 Introduction and scope

This Cost-Benefit Analysis (CBA) methodology for candidate energy storage projects (in the following, “energy storage CBA methodology”) has been developed by the JRC, the European Commission’s science and knowledge service, in compliance with the requirements set in Article 11(8) of Regulation (EU) 2022/869 (in the following, “TEN-E Regulation”) [1]. The energy storage CBA methodology has been developed to ensure a harmonised energy system-wide cost-benefit analysis at Union level and that it is compatible in terms of benefits and costs with the methodology developed by the ENTSO for Electricity and the ENTSO for Gas pursuant to Article 11(1) of TEN-E Regulation.

This energy storage CBA methodology was developed in a transparent manner, including extensive consultation of Member States and all relevant stakeholders.

1.1 The TEN-E Regulation

The Trans-European Networks for Energy (TEN-E) is a policy instrument focused on developing and linking the energy infrastructure of European Union (EU) countries. A well-planned and integrated energy infrastructure is essential to achieve such objectives: energy infrastructure is the part of the system that enables renewable energy to be incorporated into the grid, and then transmits and distributes energy across the EU from the supply source (whether imported or generated within the EU) to the end user, or stores energy until it is needed. Energy infrastructure provides for a reliable and secure energy system that helps to keep energy prices in check.

The revised TEN-E Regulation, entered into force in June 2022, lays down guidelines for the timely development and interoperability of the priority corridors and areas of trans-European energy infrastructure contributing at mitigating climate change by supporting the achievement of the EU climate and energy 2030 targets and the EU climate neutrality objective by 2050 at the latest:, and to ensuring interconnections, energy security, market and system integration and competition that benefits all Member States, as well as affordability of energy prices. More specifically, the TEN-E Regulation:

- provides for the identification of projects on the Union list of projects of common interest (PCIs) and of projects of mutual interests (PMIs);
- facilitates the timely implementation of the Union list by streamlining, coordinating more closely and accelerating permit granting processes, and by enhancing transparency and public participation;
- provides rules for the cross-border allocation of costs and risk-related incentives for projects on the Union list.

A project of common interest needs to meet general criteria and is assessed against specific criteria as set out in the TEN-E Regulation.

1.2 General criteria for candidate energy storage projects

Candidate energy storage projects need to demonstrate that the:

- project is necessary for at least one priority corridor for electricity set out in points 1 and 2 in Annex I to the TEN-E Regulation, as described in Article 4(1)(a) of TEN-E Regulation;
- potential overall benefits of the candidate project, assessed in accordance with the relevant specific criteria, outweigh its costs, including in the longer term, in line with the provisions set in Article 4(1)(b) of TEN-E Regulation. . In particular, to verify compliance with this criterion, the application must include the calculation of the Economic Net Present Value (ENPV) of the candidate project along the whole duration of the technical lifetime of the project.

Pursuant to Article 4(1)(c) of TEN-E Regulation, the candidate project shall either:

- involve at least two Member States by directly or indirectly, via interconnection with a third country, crossing the border of two or more Member States or
- be located in the territory of one Member State, either inland or offshore, including islands, and has a significant cross-border impact as set out in point (1)(b) of Annex IV to TEN-E Regulation: "*the project provides at least 225 MW installed capacity and has a storage capacity that allows a net annual electricity generation of 250 GW-hours/year*".

In its assessment of applications received, the Regional Group shall check the compliance with respect to the rules in terms of energy infrastructure categories set for storage facilities in Annex II(1) to TEN-E Regulation. In particular, project promoters must ensure that their applications are compliant with the following rules:

- energy storage facilities, in individual or aggregated form, used for storing energy on a permanent or temporary basis in above-ground or underground infrastructure or geological sites, provided they are directly connected to high-voltage transmission lines and distribution lines designed for a voltage of 110 kV or more. For Member States and small isolated systems with a lower voltage overall transmission system, those voltage thresholds are equal to the highest voltage level in their respective electricity systems;
- any equipment or installation essential for the energy storage facilities to operate safely, securely and efficiently, including protection, monitoring and control systems at all voltage levels and substations.

1.3 Specific criteria for candidate energy storage projects

Pursuant to Article 4(3)(a) of the TEN-E Regulation, the project promoter shall clearly show how the candidate project contributes significantly to sustainability through the integration of renewable energy into the grid, the transmission or distribution of renewable generation to major consumption centres and storage sites, and to reducing energy curtailment, where applicable, and contributes to at least one of the following specific criteria:

(i) market integration, including through lifting the energy isolation of at least one Member State and reducing energy infrastructure bottlenecks, competition, interoperability and system flexibility;

(ii) security of supply, including through interoperability, system flexibility, cybersecurity, appropriate connections and secure and reliable system operation;

2 General approach

The aim of the current CBA methodology is to deliver a general guideline on how to assess energy storage projects from a cost and benefit point of view. In compliance with the provisions about specific criteria set in Article 4(3)(a) of TEN-E Regulation (see section 1.2), this CBA methodology is taking into consideration the criteria of sustainability, market integration and the security of supply for developing a systematic method for quantifying the total expected benefits of the candidate PCI energy storage project. Following this process, the potential overall benefits are compared to the projected or estimated costs of the candidate PCI project, as the main purpose of this CBA is to determine whether the total benefits outweigh the total costs.

In line with the provisions set in Article 11 of TEN-E Regulation and similarly to the methodological approach used for candidate electricity transmission projects [7] and gas infrastructure projects [8], the assessment of candidate energy storage projects shall take into consideration pertinent assumptions concerning future scenarios, the definition of the reference network used to assess the impact of the project; and the techniques to be used in calculating costs and benefits for the candidate energy storage project.

2.1 Scenarios and assumptions

Scenarios are a description of contrasted yet plausible futures that can be characterised by a combination of demand and supply assumptions. With reference to the assessment of candidate storage projects, such scenarios shall consider possible development for the electricity, gas and hydrogen systems, energy exchanges within the modelled system (according to the different level of detail, it can encompass the geographical area immediately affected by the project or a wider area) and with the modelled systems. These different future developments can be used as input parameter sets for subsequent simulations and analyses.

The following list of assumptions and parameters need to be consistent for all candidate projects' applications:

— duration of the CBA horizon. As a general assumption, the horizon should be the minimum between a) the longest technical lifetime of any equipment and b) the maximum reference period for energy projects as referred to in Article 15(2) and Annex I to Commission Delegated Regulation (EU) 480/2014 [13]. The duration of the CBA horizon shall not be in any case higher than the CBA horizon of the harmonised energy system-wide cost-benefit analysis methodology for projects on the Union list falling under the energy infrastructure categories set out in point (1)(a), (b), (d) and (f) and point (3) of Annex II to TEN-E Regulation;

— fuel prices for each Member State and for each year within the CBA horizon. This assumption should be consistent with the most updated TYNDP scenarios;

— EU Emissions Trading System (EU ETS) carbon price for each year within the CBA horizon. This assumption should be consistent with the most updated TYNDP scenarios;

— shadow cost of carbon for each year within the CBA horizon. As a general assumption, values for the shadow cost of carbon within the CBA horizon should be aligned, where applicable, to shadow cost of carbon values in Tables 5 and 6 of Commission Notice 2021/C 373/01 [10];

— discount rate. As a general assumption, a 4% discount rate should be assumed, in agreement with the current value assumed for other PCI energy infrastructure categories. The discount rate should in any case be compatible with the same value defined in the harmonised energy system-wide cost-benefit analysis methodology for projects on the Union list falling under the energy infrastructure categories set out in point (1)(a), (b), (d) and (f) and point (3) of Annex II to TEN-E Regulation;

— electricity demand: for each Member State and for each year within the CBA horizon. This assumption should be consistent with the most updated TYNDP scenarios;

— green-house gases (GHG) (see B1) and relative Global Warming Potential (GWP[1]) factors;

[1] Global warming potential (GWP) is the heat absorbed by any greenhouse gas in the atmosphere, as a multiple of the heat that would be absorbed by the same mass of carbon dioxide

— emission and, when possible, monetisation factors for indirect non-CO_2 emissions, for each Member State and for each year within the CBA horizon. Examples of reference monetisation values for select pollutants as found in [17] are reported here below:

Table 1. Reference monetisation values for select pollutants

€2015/kg	NOx	NH3	SO2	PM2.5	PM10	VOC
low	24.10	19.70	17.70	56.80	31.80	1.61
middle	34.70	30.50	24.90	79.50	44.60	2.10
high	53.70	48.80	38.70	122.00	69.10	3.15

Source: [17]

— classification of synthetic fuels (see B4) and prices, for each Member State and for each year within the CBA horizon. This assumption should be consistent with the most updated policy scenarios from the Commission and/or TYNDP scenarios;

— value of lost load (VOLL) for each Member State (or zone if available) and for each year within the CBA horizon. This assumption should be consistent with the most updated policy scenarios from the Commission and/or TYNDP scenarios;

— monetisation factors for RES curtailment for each Member State and for each year within the CBA horizon.

2.1 Project implementation status

In order to support the process for establishing the regional list of projects pursuant to Annex III to the TEN-E Regulation, project promoters for candidate PCI process shall declare in their applications the level of maturity of the relevant projects, in line with the following stages, consistent with PCI monitoring reports developed by ACER[2]:

— projects “Under consideration”

— projects “Planned but not yet in permitting”;

— projects “Permitting”; and

— projects “Under construction”

2 *PCI monitoring* | www.acer.europa.eu. (2023). https://www.acer.europa.eu/gas/infrastructure/ten-e/pci-monitoring.

3 Project assessment

The assessment of candidate PCI energy storage projects shall be carried out taking the societal perspective: in line with the provisions set in Article 4(1) of TEN-E Regulation, their potential overall benefits, assessed in accordance with the relevant specific criteria, shall outweigh their costs.

— “with case”, where the candidate project is realised, it is inserted in the system and, if socio-economically desirable, realizes during its lifetime system benefits that are larger than total costs; and

— “without case” where the candidate project is not realised.

The reference network is the version of the network that is used as the starting point for the computation of benefit indicators, to calculate the incremental contribution of the project that is assessed. To determine the incremental contribution of each project, market and/or network simulations[3] are performed in which the project is either included in the reference grid or removed from it. Both market and network simulations provide different types of information and as they generally complement one another, they are often used in an iterative manner.

The calculation of the difference in indicators between the “with” and the “without” cases allows to compute benefits. For instance, the amount of energy stored by a candidate storage project is equal to the difference in storage in the “with” case (i.e. the project is built) and the “without case” (i.e. the project is not built).

In some cases, the calculation of benefits does not need a complex modelling exercise representing the whole system: in other cases, however, system modelling activities are required in case of indicators capturing system properties. For instance, an accurate assessment of the benefit “reduction of RES curtailment” would require an exhaustive modelling of the electricity system if the energy storage project is directly interconnected to the electricity system, as the candidate storage project might affect RES curtailment in function of different operating characteristics of the system (i.e. availability of transmission capacity to transfer RES curtailment from its origin to the electricity node where the storage project is connected). In some cases, simplifications might be introduced to reduce the modelling complexity (for instance, analysis in specific snapshots extended through duration curves to the whole year of operation), although there is trade-off between modelling tractability[4] and accuracy of the analysis.

Benefits and costs are calculated for one year of operation, although the technical lifetime of a candidate energy storage project is higher. To fully capture the net benefits created by the candidate project in time, then, this energy storage project CBA methodology requires the use of the discounted cash-flow method: in particular, annual cash flows (considering costs and benefits for the system) will be discounted using the discount rate defined in the information set accompanying the project submission template.

3.1 Benefits

While the calculation of each benefit should aim for a monetary value, the lack of data and models may impede the full monetization of some benefits, although such monetization may be feasible in future assessments. In such cases the quantitative/qualitative assessment of the benefits are to be considered. In general, the indicators can be:

— **Monetised:** they are expressed in monetary terms.

— **(Non-monetised) quantified:** they are quantified but not expressed in monetary terms

— **Qualitative:** they are expressed in qualitative terms (for instance, “++”, “+”, “0”, etc.).

Table 2 presents the indicators and their relevant criterion.

(3) A combination of market and network simulations, i.e., redispatch simulations can also be used

(4) Model tractability refers to the increased model granularity (e.g. from hours to quarter) which raises the computational time and the requirements.

Table 2. Benefit indicators, criteria and legal references.

Benefit code/name	Specific Criterion	Article 4 of TEN-E Regulation
B1: Socio-economic welfare in electricity markets	Market integration	point 3(a)(i)
B2: GHG emissions	Sustainability	point 3(a)
B3: RES integration	Sustainability	point 3(a)
B4: Non-CO2 emissions	Sustainability	point 3(a)
B5: Grid Losses	Sustainability	point 3(a)
	Market integration	point 3(a)(i)
	Security of supply	point 3(a)(ii)
B6: Electricity balancing markets services	Sustainability Market integration Security of supply	point 3(a) point 3(a)(i) point 3(a)(ii)
B7: Other ancillary services markets	Sustainability Market integration Security of supply	point 3(a) point 3(a)(i) point 3(a)(ii)
B8: Adequacy to meet demand	Security of supply	point 3(a)(ii)
B9: Generation capacity deferral	Sustainability	point 3(a)
B10: Transmission capacity deferral	Sustainability	point 3(a)
B11: Variation of redispatch services	Sustainability	point 3(a)
	Market integration	point 3(a)(i)
	Security of supply	point 3(a)(ii)

The following subsections describe how benefit indicators must be calculated in line with the specific criteria set in Article 4(3) of TEN-E Regulation.

3.1.1 B1 – Variation of socio-economic welfare in electricity markets [€/a]

Indicator definition:

- Definition: variation of Social Economic Welfare (SEW) in day-ahead and intra-day electricity markets achievable thanks to the candidate storage project
- Relevance: candidate storage projects can enhance flexibility and efficiency of electricity markets, resulting in an increase of SEW for the Union

Indicator Calculation:

- Modelling needs: modelling for the calculation of the benefit must cover energy storage facilities as set out in point (1)(c) of Annex II to the TEN-E Regulation. The accurate assessment requires a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). The modelling shall be able to capture different phases of wholesale electricity markets, in particular the forward, day-ahead, and intra-day markets, simulating the flexibility capability and related benefits that candidate storage projects can supply to such markets.
- Data needs: scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Simulation model and analysis for day-ahead markets shall have at least the same level of detail of the ones used and performed by ENTSO-E in its TYNDP. Level of detail of representation of intra-day markets shall be consistent with the modelling approach used for day-ahead markets. Estimations of RES amount potentially stored, RES marginal cost, and expected bids of displaced peakers (or expected peak prices) are required in case of simplifying assumptions.
- How the benefit is expressed: the benefit is expressed in monetary terms, either based on the generation cost approach or on the total surplus approach.

Link with other CBA indicators

- B2, B3

Link with specific criteria TEN-E Regulation

- Market integration: point 3(a)(i) of Art. 4

Notes/Double counting effects

- These surplus effects are only one part of the overall economic benefit provided by electricity storage investments that stem from wholesale energy market integration and do not capture other storage related benefits as described by the other indicators, as given in this methodology.
- Economic effect of the related GHG reduction is included based on ETS prices. Potential further benefits from the difference between Social Cost of Carbon (Shadow costs of CO) and such prices are taken into account through the sensitivity analysis in benefit B2.
- The sum over the monetary part of RES and CO2 can exceed the total SEW delivered

Introduction

Socio-economic welfare (SEW) is defined in economics via the concept of utility, i.e. the value that different actors in the market associate to a particular good or service. Individuals tend to maximise their utility through their actions and consumption choices and the interactions of sellers/producers and buyers/consumers as resp. supply and demand in competitive markets yield to consumer and producer surplus. A natural equilibrium point is achieved when the highest overall (social) level of satisfaction is created among the different actors.

In power system economics, SEW is often defined as the economic surpluses of electricity consumers, producers and, given the nature of the transportation problem, network operators (collecting congestion rents). Any infrastructural project inserted in the system affects either the generation or the consumption mix or the transmission capacity, resulting into a variation and/or redistribution of SEW within the modelled system (between different actors and/or among different modelled zones). In particular, storage resources allow to relieve the fundamental intertemporal constraint of electricity systems, namely, the fact that the demanded energy has to be generated contemporaneously. This does much to alleviate supply reliability issues at times of stress, especially where shares of firm generation are shrinking. Consequently, the value of storage soars in systems dominated by vRES. Storage facilities may enable a large proportion of demand to be met by cheaper generation units (arbitrage). In that context, charging of energy storage may involve the purchase of cheap energy from the wholesale energy market (i.e, for storing excess low-cost generation). Then, during times when energy is more expensive and in higher demand, storage facilities may discharge to resell energy on the wholesale market at a higher price or reduce the need to purchase electricity from expensive peaking generation. Annex 1 provides a simple example to illustrate the fundamental logic behind the estimation of SEW benefits from storage in wholesale electricity markets.

Energy storage projects can create social surplus by operating on the EU's electricity markets. The current EU electricity market design offers them the following opportunities to do so:

- participating in the day-ahead electricity market, acting as implicit (price-based) demand response. In this respect, energy storage projects can vary their consumption according to price signals: for instance, they can quickly ramp up their demand at times where there is RES surplus (reducing RES curtailment) and especially in hours where operational constraints on inflexible generation might result in negative prices, increasing societal SEW;
- participating in the intraday electricity market: energy storage projects can adjust their consumption profile in continuous trading, matching buy or sell orders in order to balance positions: in this respect, energy storage projects might act as an additional flexibility resource in intraday electricity markets, contributing at increasing societal SEW.

Calculation process

Benefit B_1 can be calculated as follows:

1. For the candidate storage project which is connected to the power system, the increase of SEW can be evaluated following one of the two approaches below:

   a) The generation cost approach, which compares the generation costs with and without the project for the different bidding areas. In this context, an economic optimisation is undertaken to determine the optimal dispatch cost of generation, with and without the project. and the socio-economic welfare, is expressed in terms of savings in total generation costs.

   b) The total surplus approach, which compares the producer and consumer surpluses for both bidding areas, as well as the congestion rent between them and possibly the cross-sector rents stemming from the interlinkage between the sectors, with and without the project. The total surplus approach takes the value of serving a particular unit of load into account. An economic optimisation is undertaken to determine the total surpluses stemming from the stakeholders involved in the sector.

   Then the evaluation of the increase in SEW could be based on a detailed modelling exercise. In this case, the operation of the modelled electricity system is evaluated in both "with" and "without" cases, given the objective function of the optimisation algorithm and the balance demand constraints. The model provides as output the level of SEW variation, in each modelled zone.

   If detailed modelling is not feasible, the approach with simplified assumptions should be followed. In this case:Calculation of the estimated SEW variation that can be created by redirecting a certain amount of RES generation infeed to the candidate energy storage project, and the difference between its marginal cost of production and the expected bid of production of the non-RES generation it displaces (proxied by expected peak prices if not directly available). All the assumptions must be duly justified and referenced.

2. The hourly monetised benefit related to SEW variation in the z-th zone of the modelled electricity system can be calculated as follows:

$$B_1 = \sum_z [SEW_{wholesale}|_{with} - SEW_{wholesale}|_{without}]$$

—

3. The hourly monetised benefit related to SEW variation in the z-th zone of the non-modelled electricity system can be calculated as follows:

$$B_1 = \sum_z \left(E(bid)_z|_{peaker} - MC_z|_{RES}\right) \cdot K_{RES\_stored_z}$$

— where $bid_z|_{peaker}$ can be proxied by expected peak prices if not directly available.

4. The economic present value of indicator B_1 is calculated within the CBA horizon using the discounted cash-flow approach.

3.1.2 B2 – Variation of GHG emissions [tonne/a, €/a]

<u>Indicator Definition</u>:

- Definition: economic valorisation of the variation of greenhouse gases emission achievable thanks to the project.
- Relevance: energy storage projects are key infrastructural projects for serving electricity demand with a lower carbon footprint by enabling the integration of additional RES, so to replace usage of GHG-emitting fuels.

<u>Indicator Calculation:</u>

- Modelling needs: modelling for the calculation of the benefit must cover energy storage facilities as set out in point (1)(c) of Annex II to the TEN-E Regulation. The accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). The modelling shall be able to capture different phases of electricity markets, in particular the forward, Day-Ahead, Intra-Day, and balancing markets, simulating the flexibility capability and related benefits that candidate storage projects can supply to such markets.
- Data needs: scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Simulation model and analysis for day-ahead markets shall have at least the same level of detail of the ones used and performed by ENTSO-E in its TYNDP. Level of detail of representation of intra-day and balancing markets shall be consistent with the modelling approach used for day-ahead markets. Estimations of RES amount potentially stored and expected emissions of displaced peakers or Balancing Service Providers (BSPs) are required in case of simplifying assumptions.
- How the benefit is expressed: the benefit is originally calculated in quantitative terms (tonnes of equivalent carbon emission savings) and it is converted in monetary terms by the tons of CO_2 emission savings are multiplied by the societal cost of carbon (shadow cost of carbon).

<u>Link with other CBA indicators</u>

- B1, B3, B5, B6

<u>Link with specific criteria TEN-E Regulation</u>

- Sustainability: point 3(a) of Art. 4

<u>Notes/Double counting effects</u>

- The societal cost of CO_2 is different from the price of CO_2 that is imposed on carbon-based electricity production, which may take the form of carbon taxes and/or the obligation to purchase

CO_2 emission rights under the Emissions Trading Scheme (ETS). The cost of the latter is internalised in production costs and is fully captured by indicator B1. In order to not double account with the CO2 variation already monetised into the SEW (B1) variation in CO_2 emission are multiplied by the difference between the CO_2 societal cost and the ETS price used in the scenario.

Introduction

Energy storage projects can reduce GHG emissions by displacing polluting peak generation with low-carbon low-cost energy stored off-peak and by reducing volumes of network losses. EU emissions in the electricity sector are covered by the EU ETS cap-and-trade scheme, whereby a certain price is associated with the permission to release one tonne of CO_2 into the atmosphere. GHG-emitting technologies are therefore faced with higher costs, which in turn translate into the prices they are able to bid on the electricity markets.

To the extent that ETS prices capture the social cost of CO_2 emissions, then, electricity prices determining the Socio-Economic Welfare at benefit B1 and B6 already include part of the shadow cost of carbon. However, the cost of CO2 imposed on electricity producers does not necessarily reflect the total societal effect nor does it give the necessary incentive to reach the European climate goal. Setting the value of avoided CO2 emissions is a political choice. In order to avoid the double account with the CO2 variation already monetised into the SEW (B1) the changes in CO2 emission are multiplied by the difference between the CO2 societal cost and the ETS price used in the scenario.

Calculation process

1. The amount of avoided emissions equals to the amount of polluting generation displaced by stored low-carbon generation multiplied by the difference in their emission factors (defined as coefficients describing the rate at which a given activity releases greenhouse gases).

2. Evaluation of the amount of GHG emissions avoided thanks to the candidate energy storage project based on the following approach:

- a detailed modelling exercise is carried out, in which the project promoter must evaluate the operation amount of GHG-emitting generation in both the “with” and “without” cases. Given the objective function of the optimisation algorithm and the combination of the active constraints of the problem, the model provides as output the variation in GHG emissions achievable thanks to the project.

If detailed modelling is not feasible, the approach with simplified assumptions should be followed:

- Calculation of the Emission Factor difference based on the most granular carbon intensity data available, and the amount of GHG-emitting generation displaced based on their knowledge of the operational capability of the project. Current and past zonal emission factors can be sourced from data underlying real-time zonal carbon intensity maps available at Electricity Maps website [14]. Prospective carbon intensities can be imputed by interacting such data with installed generation capacities in the scenarios considered, as compliant with TYNDP scenarios (Article 12 TEN-E Regulation). All the assumptions must be duly justified and referenced.

The z-th zone variation of GHG emissions achievable thanks to the candidate project is converted into monetary terms. In order to not double account with the CO2 variation already monetised into the SEW (B1) variation in CO2 emission are multiplied by the difference between the CO2 societal cost and the ETS price used in the scenario. The calculation of this difference should be applied only when the ETS costs are lower than the defined societal costs. If the ETS costs are already above the societal costs, only the ETS costs are used and this indicator does not bring additional monetary benefit.

The societal cost of carbon can represent the shadow price that is determined by the climate goal under consideration. It can be interpreted as the willingness to pay for imposing the goal as a political constraint. The European Commission’s Vademecum [15] provides guidance on appropriate shadow costs of carbon for 2020-2050 as best available evidence on the cost of meeting the temperature goal of the Paris Agreement.. The social cost of carbon used for monetisation should be provided in the information set accompanying the project submission template:

$$B_1 = \sum_{Z} [emission|_{without} - emission|_{with}] \cdot (ShCost_{CO_2} - ETS_{CO_2})$$

3. The economic present value of indicator B_2 is calculated within the CBA horizon using the discounted cash-flow approach.

4. Sensitivity analyses could be run to check the monetary values of benefits from avoided GHG emissions under different assumptions about their social costs (Annex V(2) of the TEN-E Regulation). This is a separate exercise from checking the effect of assumptions on future ETS CO2 prices contained in different scenarios, for it is carried out leaving the merit order, and hence the whole simulation, thoroughly unchanged.

3.1.3 B3 – RES integration [MWh

Indicator Definition:

- Definition: Reduction of renewable generation curtailment in MWh (avoided spillage) and/or the additional amount of RES generation that is connected by the project in MW.
- Relevance: Reduction of RES curtailment by using the RES surplus to feed energy storage projects connected to the electricity network and enabling connecting more RES and increases sustainability of the Union energy system

Indicator Calculation:

- An explicit distinction is made between RES integration benefit related to either:
  - Increase in the capacity of the electricity system to integrate RES without curtailment risk - The capacity-based indicator is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system; or
  - The direct connection of RES to the main system - Direct connection is expressed in MW RES-connected (without regard for actual avoided spillage).
- Both types of indicators may be used for the project assessment, provided that the method used is reported. In both cases, the basis of calculation is the amount of RES foreseen in the scenario or planning case.
- Modelling needs: modelling for the calculation of the benefit must cover energy storage facilities as set out in point (1)(c) of Annex II to the TEN-E Regulation. The accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). An alternative solution without significant modelling requirements would be based on project and system assumptions and relative calculations.
- Data needs: scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Extensive data requirement to simulate the whole electricity system (i.e. simulations up to the European level would require additional data). In absence of extensive modelling, the benefit can be calculated by using operative data about the estimated amount of additional RES whose curtailment can be avoided thanks to the candidate storage project as well as about the amount of available RES curtailment.
- How the benefit is expressed: the benefit can be expressed in quantitative terms as avoided RES curtailment in the electricity system (in GWh/a) achievable thanks to the candidate project and in monetary terms, by multiplying the avoided RES curtailment for RES curtailment valorisation factors to be provided in the information set accompanying the project submission template.

Link with other CBA indicators

- B1, B2

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4
- Market integration: point 3(a)(i) of Art. 4
- Security of supply: point 3(a)(ii) of Art. 4

Notes/Double counting effects

- Indicator B3 reports the increased penetration of RES generation in the system. As this also affects the input parameters of the simulation runs, the economic effects, in terms of variable generation costs and CO_2 emissions, are already fully captured in other indicators, like B1 and B2.

Introduction

Energy storage can either directly help connecting more RES, e.g. for an aggregator of variable RES, energy storage can enable a higher RES uptake as it facilitates managing imbalances (and optimising the bidding); or avoid RES curtailment, e.g. when there is too much RES in (a part of) the system, instead of curtailing the infeed the aggregator can absorb the energy internally in the storage. Both aspects can be somehow overlapping, but not 100% (i.e. not all additional enabled RES MW will translate in a 1-to-1 relation of avoided RES curtailments).

RES curtailment arises in the electricity system when the instantaneous production of variable renewable energy sources exceeds the instantaneous electricity demand, taking also in consideration the inflexibility of certain components of the electricity system (for instance, minimum up time and downwards ramp constraints of dispatchable thermal power plants). In this occurrence, if the electricity system is not able to store or transmit such surplus in other areas of the system, system operators might force RES to reduce their output to ensure system security: consequently, the system is not exploiting a source of cheap and clean energy output.

While energy storage projects might have technical operational constraints, they can still provide additional flexibility to the energy system as a whole, increasing their intake in RES surplus moments to store energy that can be released at peak load. This capability can be beneficial under different perspectives:

- by reducing the curtailment of renewable energy that it is instead stored to be used at a second stage, candidate energy storage projects can enable additional decarbonisation of end-uses increasing the sustainability of the whole energy system;
- the reduction of curtailment for RES generation contributes at increasing the safety and the stability of network operation, enhancing security of supply; and
- the flexibility provided by candidate energy storage projects can be seen as a measure of demand response in the electricity system enabling energy storage: consequently, candidate energy storage projects contributing at reducing RES curtailment facilitate market integration, competition and system flexibility, promoting the intertemporal convergence of market prices, and ultimately unlocking cost savings for the Union.

B3.1 Share of electricity generated from renewable sources (non-monetised)

The increment of renewable capacity that can be incorporated in the system thanks to the energy storage project should be provided. This means the change (Δ) in renewable capacity uptake that the project enables further to what would have been incorporated anyhow without the energy storage project, and not the absolute / total amount of renewables expected in the geographical area of the project neither the change in uptake with respect to the current amount of renewables at the time of submission of the PCI candidate application.

This indicator quantified in terms of percentage variation of the share of electricity generated from renewables that can be safely integrated in the system between the “with” and the “without” project scenarios (over a defined period of time), assuming the same total amount of electricity consumed in both scenarios:

$$B_{3.2} = \frac{E\ RES_{with} - E\ RES_{without}}{E_{total}}$$

Where:

- $E\ RES_{with}$ and $E\ RES_{without}$ represent the amount of electricity generated from renewable sources in the "with" and "without" cases [MWh];

- E_{total} is the total energy consumption in the geographical area affected by the project under consideration in the defined period (it is assumed constant before and after the storage project realisation) [MWh].

The calculation of RES energy requires the estimation of the installed capacity [MW] and of the equivalent running hours of the different types of RES units considered [h/year]. It should be demonstrated clearly and transparently how the estimations were carried out.

B3.2 Reduction of renewable generation curtailment (non-monetised)

The indicator is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system. It measures the reduction of renewable generation curtailment in MWh (avoided spillage) and the additional amount of RES generation that is connected by the energy storage project. Avoided spillage is extracted from the studies for indicator B1.

The volume of integrated RES (in MWh) must be reported as the integration of both existing and planned RES is facilitated by:

- The connection of RES generation to the main power system; and
- Increasing the capacity between one area with excess RES generation to other areas in order to facilitate an overall higher level of RES penetration.

The indicator which is used to quantify the benefit of RES integration in quantitative figures is the additional amount of RES energy used in the power system as a consequence of the change on the generation dispatch, in MWh/year. This additional RES energy displaces non-RES energy from the power system. It is computed as the additional yearly RES energy of the connected power (if any), reduced by the additional dumped energy in the system resulting from the addition of the project. Hence, the benefit, conceptually similar to the benefit B3 "RES Integration Benefit" considered in the ENTSO-E methodology [7], can be calculated as follows:

$$B_{3.2} = (\mathrm{RES}_{\mathrm{project}} - (RES\_curtailment\ |_{with} - RES\_curtailment\ |_{without})$$

where:

- RES_{add} :the additional yearly energy produced by the connected RES source
- $RES\_curtailment_{with}$:the yearly curtailed energy with the project included
- $RES\_curtailment_{without}$:the yearly curtailed energy without the project included

3.1.4 B4 – Variation of non-CO_2 emissions [tonne/a, €/a]

Indicator Definition:

- Definition: economic valorisation of the variation of non-greenhouse gases emission achievable thanks to the project.
- Relevance: energy storage projects are key infrastructural projects for serving electricity demand with a lower emission footprint by replacing usage of polluting fuels.

Indicator Calculation:

- Modelling needs: modelling for the calculation of the benefit must cover energy storage facilities as set out in point (1)(c) of Annex II to the TEN-E Regulation. The accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). The modelling shall be able to capture different phases of electricity markets, in particular the forward, Day-Ahead, Intra-Day, and balancing markets, simulating the flexibility capability and related benefits that candidate storage projects can supply to such markets.
- Data needs: scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Simulation model and analysis for day-ahead markets shall have at least the same level of detail of the ones used and performed by ENTSO-E in its TYNDP. Level of detail of representation of intra-day and balancing markets shall be consistent with the modelling approach used for day-ahead markets. Estimations of RES amount potentially stored and expected emissions of displaced peakers or Balancing Service Providers (BSPs) are required in case of simplifying assumptions.
- How the benefit is expressed: the benefit is originally calculated in quantitative terms (tonnes of equivalent non-GHG emission savings) and it is converted in monetary terms by means of the social cost of non-CO_2 emissions defined in the information set accompanying the project submission template.

Link with other CBA indicators

- B1, B3

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4

Introduction

Further benefits from energy storage projects can be realised thanks to the reduction in non-GHG emissions. These projects can reduce such emissions by displacing polluting peak generation with low-emission low-cost energy stored off-peak. As elaborated below, effects of potential differences in the assumed social costs of pollutants should be investigated through sensitivity analyses.

Calculation process

1. The amount of avoided non-CO_2 emissions equals to the amount of polluting generation displaced by stored low-carbon generation multiplied by the difference in their emission factors (defined as coefficients describing the rate at which a given activity releases pollutants).
2. Evaluation of the amount of non- CO_2 emissions avoided thanks to the candidate energy storage project based on the following approach::
   - a detailed modelling exercise is carried out, based on the emission factors per pollutant of the various technologies displaced, in which the amount of polluting generation is evaluated in both the “with” and “without” cases. Given the objective function of the optimisation algorithm and the combination of the active constraints of the problem, the model provides as output the variation in non- CO_2 emissions achievable thanks to the project.

If detailed modelling is not feasible, the approach with simplified assumptions should be followed:

- Calculation of the Emission Factor difference based on the most granular emission intensity data available, and the amount of polluting generation displaced based on their knowledge of the operational capability of the project. Prospective emission intensities can be imputed by interacting such data with installed generation capacities in the scenarios considered, as compliant with TYNDP scenarios (Article 12 TEN-E Regulation). All the assumptions must be duly justified and referenced.

3. The z-th zone variation of emissions per each non-GHG pollutant achievable thanks to the candidate project is converted into monetary terms by using the social cost of carbon provided in the information set accompanying the project submission template.

$$B_4 = \sum\nolimits_Z [non - GHG\ emission|_{without} - non - GHG\ emission|_{with}] \cdot ShCost_{non-GHG}$$

4. The economic present value of indicator B_4 is calculated within the CBA horizon using the discounted cash-flow approach.

5. Sensitivity analyses shall be run to check the monetary values of benefits from avoided non-GHG emissions under different assumptions about their social costs (Annex V(2) of the TEN-E Regulation).

3.1.5 B5 – Variation in grid losses [€/a]

Indicator Definition:

- Definition: value of changes in grid losses, hence the amount of generation needed to cover demand, induced by variations in power flow patterns linked to energy storage projects.
- Relevance: installation of storage projects in the system can modify flow patterns and lead to higher or lower network losses, hence generation costs and pollutant emissions.

Indicator Calculation:

- Modelling needs: accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). An alternative solution without significant modelling requirements would be based on project assumptions and relative calculations.
- Data needs: if detailed modelling is introduced, extensive data requirement to simulate the whole electricity system (i.e. simulations up to the European level would require data requirements similar to the ones for ENTSOs TYNDPs). In absence of extensive modelling, the benefit can be calculated but using operative data about the estimated amount of energy potentially stored, hypotheses on the most prevalent sources of generation employed for recharging and replaced by discharging, and the related fuel cost prices, emission factors, and social costs of pollutants.
- How the benefit is expressed: the benefit can be expressed in quantitative terms as the losses-related variation in generation needed to cover demand. It can be converted into monetary terms when the amount of variation is multiplied by cost of generation avoided or required, possibly proxied by relevant electricity prices.

Link with other CBA indicators

- B1, B2, B3, B6

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4
- Market integration: point 3(a)(i) of Art. 4
- Security of supply: point 3(a)(ii) of Art. 4

Introduction

Electricity losses are an inevitable consequence of transferring energy across electricity networks. Technical losses, in particular, are caused by the physical properties of the components of the power system and consist mainly of power dissipation in electrical system component such as transmission lines, power transformers, and substations. Technical losses are computable based on load and dispatch patterns within the system at hand.

A higher share of generation close to consumers would reduce energy losses and grid congestion. However, renewable energy sources are not always thus sited, and their production is not always dispatchable. As a result, generation production might not coincide with demand requirements, and storage capacity needs to be readily available for this purpose. Clearly, this does not mean that the addition of storage facilities comes without costs.

At constant power-flow levels, network development generally decreases losses, thus increasing network efficiency. However, the addition of storage capacity may increase flows and network utilisation, and therefore technical network losses. Given detailed system modelling of Day Ahead Market (DAM) and balancing dispatch, an accurate assessment of flows can be derived that induces a certain variation in power generation patterns needed to serve demand. This will determine changes in losses that can then be monetised based on marginal costs in relevant zonal supply schedules, possibly proxied by prices.

Calculation process

The benefit can be calculated as follows:

1. Evaluation of the variation in losses on the following approach:

   - a detailed modelling exercise is carried out, in which the operation of the modelled electricity system is evaluated in both "with" and "without" cases. Given the objective function of the optimisation algorithm and the balance demand constraints, the model provides as output the amount of losses, in each modelled zone. Their variation can be quantified as follows:

$$\Delta losses_Z = \sum_Z [losses|_{with} - losses|_{without}]$$

If detailed modelling is not feasible, the approach with simplified assumptions should be followed:

   - calculation of the variation in losses in the z-th zone as a given fraction of demand in the "with" and "without" cases, given the project's expected impact on prices. Average system losses vary widely across EU Member State. It is therefore recommended to adopt relevant recent estimates by the TSOs. All the assumptions must be duly justified and referenced.

$$\Delta losses = \sum_Z [K(demand|_{with} - demand|_{without})]$$

where K is the fraction of demand composing losses.

2. Monetisation can be carried out as follows:

a. In the modelled case, the hourly monetised benefit (or cost) related to losses variation in the *z*-th zone of the modelled electricity system can be calculated as follows:

$$B_5 = \sum_Z [losses * P_Z|_{with} - losses * P_Z|_{without}]$$

b. The hourly monetised benefit related to losses variation in the z-th zone of the non-modelled electricity system can be calculated as follows:

$$B_5 = \sum_Z MC_Z[K(demand|_{with} - demand|_{without})]$$

where *MC* is the Marginal Cost of generation needed to cover the difference in losses, possibly proxied by an interpolation of zonal prices in the "with" and "without" cases.

In principle, losses are part of demand. Adjustments in demand and flows based on price shifts induced by the candidate project determine variations in losses that in turn change demand. By iteration, ideally an equilibrium is found where prices sustain a pattern of flows (and thus losses) whose associated demand is induced by those same prices. By such a procedure, losses would be entirely included in SEW. However, according to the characteristics and approximations of the simulation model, there could be risk of double counting with other indicators, for instance with B1 and B6: in this case, these risks should be clearly identified and the share of the indicator which is already accounted in another one should be removed. A discussion of how to address this- within the specific ENTSO-E TYNDP modelling context - can be found in ENTSO-E [7], pp. 66 ff.

3. The economic present value of indicator is calculated within the CBA horizon using the discounted cash-flow approach.

3.1.6 B6 – Variation of electricity balancing markets services [€/a, ordinal scale]

Indicator Definition:

- Definition: variation of electricity balancing markets services achievable thanks to the candidate storage project.
- Relevance: candidate storage projects can enhance flexibility and efficiency of electricity markets, resulting in an increase of SEW for the Union.

Indicator Calculation:

- Modelling needs: if the project is connected to the electricity network and not to a dedicated and exclusive RES infeed, the accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). The modelling shall be able to capture different phases of electricity markets, in particular closer to real-time (for instance, balancing markets and ancillary services markets), simulating the flexibility capability and related benefits that candidate storage projects can supply to such markets.
- Data needs: Scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Simulation model and analysis for balancing markets shall be consistent with the modelling approach used for day-ahead and intra-day markets for benefit B1. Estimations of balancing capacity needs based on largest trip in the relevant area, or RES amount potentially stored, of RES marginal cost, of expected bids of displaced Balancing Service Providers (BSPs) (or expected balancing energy prices), and of relative frequency of balancing activation, are required in case of simplifying assumptions.
- How the benefit is expressed: the benefit is expressed in monetary terms either by following the generation cost approach or the total surplus approach. Alternatively the benefit can be expressed qualitatively, using the ordinal scale.

Link with other CBA indicators

- B1, B2, B3

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4
- Market integration: point 3(a)(i) of Art. 4
- Security of supply: point 3(a)(ii) of Art. 4

Notes/Double counting effects

- Economic effect of the related GHG reduction is included based on ETS prices. Potentially different benefits due to divergence between the Shadow Cost of Carbon and such prices are taken into account in benefit B2.
- Depending on the characteristics of the simulation model, there could be risk of double counting with other indicators, notably B1 and B2: in this case, these risks should be clearly identified and the share of this indicator that is already accounted in another one should be removed.

Introduction

Balancing services are the mechanisms in place to ensure that the grid operates at the correct frequency. Balancing services is one out of many ancillary services that system operators have to provide a secure power supply and they include balancing energy and balancing capacity. Balancing energy means the energy which is used by system operators to perform the maintenance of the frequency and balancing capacity refers to a flexible capacity which should be kept available for a certain period in order to provide balancing energy.

The purpose of the balancing market is to correct the imbalance between production and demand in real time, maintaining the technical standards of the system. Exchange and sharing of ancillary services products, in particular balancing energy exchanges, is crucial to increase RES integration and to enhance the efficient use of available generation capacities. Storage projects are expected to increase electric system capabilities for balancing energy needs thus having positive impact on exchange balancing energy in the context of high penetration of non-dispatchable electricity generation.

The balancing services indicator shows welfare savings through the exchange of balancing energy and imbalance netting. Balancing energy refers to products such as Replacement Reserve (RR), manual Frequency Regulation Reserve (mFRR), and automatic Frequency Regulation Reserve (aFRR). Another important indicator for system balancing is exchanging/sharing balancing capacity. TSOs procure the balancing capacity needed at the national level. However, to lower the procurement costs, TSOs may opt for exchanging balancing capacity with other TSO(s). In this context, exchanging/sharing balancing capacity (i.e., RR, mFRR and aFRR) that requires guaranteed or reserved cross-zonal capacity is also taken into account.

Calculation process in monetary terms

The monetisation of balancing benefits would follow essentially the same logic as for those accruing on the Day-Ahead Market (benefits B1), only with higher granularity. The quantity of balancing generation capacity to be procured can be determined stochastically or deterministically. The former option, i.e. stochastic reserve dimensioning, requires a detailed simulation model of the EU electricity system (forward, day-ahead, intraday, balancing markets). Scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Simulation model and analysis for day-ahead markets shall have at least the same level of detail of the ones used and performed by ENTSO-E in its TYNDP. Level of detail of representation of intra-day and balancing markets shall be consistent with the modelling approach used for day-ahead markets. This exercise yields estimates of the yearly frequency where demand cannot be covered by available supply (Loss of Load Expectation, LoLE), of how much balancing capacity is needed to bring this down to the regulatory targets for such frequency (Reliability Standards), and how often such capacity is activated to this end. Thus, it allows to compare the relative balancing capacity and energy procurement costs of attaining such targets by additional peak generation capacity, or instead by deploying the candidate energy storage project.

Deterministic reserve dimensioning simplifies the analysis by assuming a fixed balancing capacity need, set equal to the largest possible trip in the relevant area. The cost difference with and without the project constitutes the monetary value of the same.

For each year within the CBA horizon, the variation of socio-economic welfare (SEW) in the EU electricity balancing markets achievable thanks to candidate projects connected to the electricity transmission network shall be evaluated. Calculation is carried out as follows:

— Evaluation of the variation of SEW [€/a] achievable thanks to the project (SEW in “with” case – SEW in “without” case) calculated by means of a detailed model for EU electricity balancing markets.

$$B_6 = \sum_z \left[SEW_{balancing}\big|_{with} - SEW_{balancing}\big|_{without} \right]$$

— The monetised benefit related to SEW variation in the z-th zone of the non-modelled electricity system can be calculated as follows:

$$B_6 = \sum_z (E(bid)_z|_{BSP} - MC_z|_{RES}) \cdot Freq_{balancing_z}$$

where $Freq_{balancing_z}$ is the average frequency of balancing energy activation in the z-th zone, representing the fraction of balancing needs which are covered by the service provider over the time of consideration. $E(bid)_z|_{BSP}$ represents the pay-as-cleared[5] price (marginal pricing) of the balancing energy for standard balancing products and specific balancing products or the expected bid of the displaced provider, given the typical Pay-As-Bid structure of the balancing markets.

— The economic present value of the variation of SEW achievable thanks to the project is calculated within the CBA horizon using the discounted cash-flow approach.

Depending on the characteristics of the simulation model, there could be risk of double counting with other indicators, notably B1 and B2: in this case, these risks should be clearly identified and the share of this indicator that is already accounted in another one should be removed.

Calculation process in qualitative terms

In the absence of full models for balancing energy markets and considering the challenges for choosing the right balance between the complexity and feasibility of completing assessments, the indicator for balancing market services can be also addressed by qualitative assessment. In this context, for the assessment of the candidate project, different technical KPIs, can be used. For instance, indicators like the frequency support reserve (FCR), could be of major relevance for the assessment, since storage systems can be used for balancing the fluctuating feed-in from renewable energies and participate in the market for frequency support reserve (FCR). Furthermore energy storage systems can participate in the frequency restoration process providing[6] frequency restoration reserves (FRR) to the electricity balancing market. Taking into consideration dedicated KPIs like FCR and FRR this assessment should be based on the expert view, considering the existing studies and the technology information. In this context, the qualitative assessment of storage projects is defined in the following Table 3.

Table 3: Qualitative assessment of Balancing Market Services Benefits of a candidate storage project

KPIs	Score "0"	Score "+"	Score "++"	Details-Reference Indications
FCR-Response time	more than 30 sec.	less than 30 sec.	less than 1 sec.	30 sec : ramp time of FCR 1 sec: typical inertia time scale
Response time –	more than 200 sec.	less than 200 sec.	less than 30 sec.	200sec: FRR ramp

[5] According to Article 6(4), of Regulation (EU) 2019/943, the settlement of balancing energy for standard balancing products and specific balancing products shall be based on marginal pricing (pay-as-cleared) unless all regulatory authorities approve an alternative pricing method on the basis of a joint proposal by all transmission system operators following an analysis demonstrating that that alternative pricing method is more efficient

[6] This provision can be either negative to compensate for excess power supply, or positive to compensate for excess demand on the power market.

including delay time of IT and control systems				time 30sec: FCR ramp time
Duration at rated power – total time during which available power can be sustained	less than 1 min.	less than 15 min.	15 min. or more	1 min : double the response time of FCR 15 min : Typical PTU[7] size
Available power – power that is continuously available within the activation time	below 20 MW	20 - 225 MW	225 MW or higher	20 MW : 1%-2% of a typical power plant is reserved for FCR and reachable from a project perspective 225 MW : PCI size

Calculation process in mixed terms (use of monetary and qualitative terms)

In the absence of full models for balancing energy markets and considering the challenges for choosing the right balance between the complexity and feasibility of completing assessments, the indicator for balancing market services can be also addressed by qualitative assessment. Following the principles of the Implementation Guidelines for TYNDP 2022 (ENTSOE 2022), the balancing benefits are addressed by qualitative assessment with the use of the following unit of measure: 0/+/++ where:

"0" indicates that the project has marginal impact on the indicator.

"+" indicates that the project has only a small to moderate impact on the indicator.

"++" indicates that the project has significant impact on the indicator.

Based on the TYNDP 2020 and 2022 results and the public studies on market integration benefits three different range thresholds can be assigned to the scores (0/+/++). In this way, the indicator can be tested to be statistically meaningful, and the range thresholds for levels of reduction of energy balancing costs are set, applying the equivalences in Table 3.

Table 3. Values and corresponding qualitative indicators

Value submitted within the range (in M €)	**Corresponding qualitative indicator**
<1.4	0
[1.4;14]	+
≥14	++

Source: Own elaboration.

[7] PTU = program time unit

3.1.7 B7 – Variation in other ancillary services markets [€/a]

Indicator Definition:

- Definition: variation in other ancillary services markets achievable thanks to the candidate storage project.
- Relevance: candidate storage projects can provide a variety of non-frequency ancillary services, resulting in an increase of security of supply and SEW for the Union.

Indicator Calculation:

- Modelling needs: accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). The modelling shall be able to capture different phases of electricity markets, in particular closer to real-time (for instance, balancing markets and ancillary services markets), simulating the flexibility capability and related benefits that candidate storage projects can supply to such markets.
- Data needs: Scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). Simulation model and analysis for ancillary services markets shall be consistent with the modelling approach used for day-ahead, intra-day, and balancing markets for benefits B1 and B6. Estimations of ancillary services needs in the relevant area, or RES amount potentially stored, of RES marginal cost, of expected bids of displaced providers of ancillary services are required in case of simplifying assumptions.
- How the benefit is expressed: the benefit is expressed in monetary terms based on expected prices for the services offered.

Link with other CBA indicators

- B1, B6

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4
- Market integration: point 3(a)(i) of Art. 4
- Security of supply: point 3(a)(ii) of Art. 4

Notes

- Economic effect of the related GHG reduction is included based on ETS prices. Potentially different benefits due to divergence between the Shadow Cost of Carbon and such prices are taken into account through the sensitivity analysis in benefit B2.

Introduction

Network stability and reliability have always been top priorities for TSOs, but with the growth of renewable energy sources on the grid, the challenges of maintaining that stability and reliability are growing. In case of black-out, storage is capable of providing black-start services. This is regularly contracted by the TSO, based on deterministic hour-by-hour demand. Storage can reduce the cost of this service at times, providing a straightforward avenue to its monetisation. Energy storage projects can efficiently provide a variety of ancillary services, including:

- Black start capability
- Reactive power supply
- Voltage control

Calculation process

For each year within the CBA horizon, the variation of socio-economic welfare (SEW) in the EU ancillary services markets achievable thanks to candidate projects connected to the electricity transmission network shall be evaluated. Calculation is carried out as follows:

— Evaluation of the variation of SEW [€/a] achievable thanks to the project (SEW in “with” case – SEW in “without” case) calculated by means of a detailed model for EU ancillary services markets.

$$B_7 = \sum\nolimits_{Z} [SEW_{ASM}|_{with} - SEW_{ASM}|_{without}]$$

— The monetised benefit related to SEW variation in the z-th zone of the non-modelled electricity system can be calculated as follows:

$$B_7 = \sum\nolimits_{z} (E(bid)_z|_{ASM} - MC_z|_{ASM})$$

— where $bid_z|_{ASM}$ represents the pay-as-cleared[8] price (marginal pricing) of the ancillary services markets for standard and specific ancillary services products or the expected bid of the displaced provider, given the typical Pay-As-Bid structure of the ancillary services markets.

[8] According to Article 6(4), of Regulation (EU) 2019/943, the settlement of balancing energy for standard balancing products and specific balancing products shall be based on marginal pricing (pay-as-cleared) unless all regulatory authorities approve an alternative pricing method on the basis of a joint proposal by all transmission system operators following an analysis demonstrating that that alternative pricing method is more efficient

3.1.8 B8 – Adequacy to meet demand [€/a]

Indicator Definition:

- Definition: Reduction in Loss of Load Expectation and Expected Energy not Served due to the additional capacity to serve demand due to the energy storage project.
- Relevance: candidate storage projects can reduce Loss of Load Expectation and Expected Energy not Served of the electricity system given the scenario's level of installed generation capacity, resulting in an increase in the Union's security of supply.

Indicator Calculation:

- Modelling needs: accurate assessment would require a detailed modelling exercise simulating a larger portion of the electricity system beyond the project (i.e. up to the European level). An alternative solution without significant modelling requirements would be based on project assumptions and relative calculations.
- Data needs: Scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). If detailed modelling is introduced, extensive data requirement to simulate the whole electricity system (i.e. simulations up to the European level would require data requirements similar to the ones for ENTSOs TYNDPs). In absence of extensive modelling, the benefit can be calculated based on project assumptions and relative calculations.
- How the benefit is expressed: the benefit can be expressed in quantitative terms as the variation in Loss of Load Expectation and Expected Energy not Served, defined respectively as the relative frequency of demand shedding and the amount of energy that is not served in such event. It can further be converted in monetary terms based on assumptions on the Value of Lost Load relevant to the zone under investigation.

Link with other CBA indicators

- B1, B6, B7

Link with specific criteria TEN-E Regulation

- Security of supply: point 3(a)(ii) of Art. 4

Notes/ Double counting effects

- The difference in cost for reaching a given reliability target for LoLE is already captured by benefits B1 and B6. In order to avoid double counting with B1 and B6, the indicator needs to be designed so to only capture the benefit from lower Loss of Load.

Introduction

Storage units can generate revenues from multiple sources, participating in the energy markets in a number of applications. Examples of these applications include frequency regulation and spinning and non-spinning reserve services (ancillary markets) and energy arbitrage (wholesale energy markets). Additionally, energy storage units can potentially benefit from their participation in the capacity markets by providing resource adequacy. Resource adequacy is of paramount importance for maintaining power system reliability. In this context, the potential capacity of the energy storage units can be defined as the maximum power rate at which the unit can continuously discharge for a certain period of time.

For any given generation capacity level in a scenario, installation of additional storage capacity decreases the frequency with which available supply is not sufficient to serve concurrent electricity demand. This results in system adequacy benefits expressed by the decrease in Loss of Load Expectation (LoLE) and in the Expected Energy not Served, that can be monetised based on the Value of Lost Load (VoLL)[9] relevant to the area.

Calculation process

The benefit can be calculated as follows:

1. Evaluation the variation in losses based on the following approach:
   - in case a detailed modelling exercise is carried out, the Loss of Load Expectation should be evaluated in both "with" and "without" cases. Given the objective function of the optimisation algorithm and the balance demand constraints, the model provides as output the frequency of load shedding in each modelled zone. Its variation can be quantified as follows:

— If detailed modelling is not feasible, the approach with simplified assumptions should be followed:

   - Calculation of the variation in Expected Energy not Served in the z-th zone in the "with" and "without" cases, computing the project's capacity to cover previously unserved demand using assumptions based on their knowledge of the operational capability of the project. All the assumptions must be duly justified and referenced.

$$\Delta EEnS = \sum_{Z} [EEnS_Z|_{with} - EEnS_Z|_{without}]$$

2. The variation in Expected Energy not Served shall be monetised based on the regulatory unitary Value of Lost Load (VoLL)[10] relevant to the area under analysis.

3. The economic present value of the indicator B8 is calculated within the CBA horizon using the discounted cash-flow approach.

[9] VoLL can be defined as the maximum electricity price that customers are willing to pay to avoid an outage (Article 2(9) of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)) and Article 2(2)(h) of the Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity (recast), 30.11.2016, COM(2016) 861 final 2016/0379 (COD)).

[10] VoLL is an estimation in €/MWh. Pursuant to Article 11 of the said Regulation (EU) 2019/943 by 5 July 2010 the EU Member States must establish a single estimate of the VoLL for their territory (it is required for the purpose of setting a reliability standard). Different VoLLs per bidding zone may be established if Member State has several bidding zones in its territory). Where a bidding zone consists of territories of more than one Member State, the concerned regulatory authorities or other designated competent authorities shall determine a single estimate of the value of lost load for that bidding zone.

3.1.9 B9 – Generation capacity deferral [€/a]

Indicator Definition:

- Definition: deferral and/or reduction of the investment need in conventional, thermal generation capacity due to the energy storage project (if storage is a more cost-effective solution).
- Relevance: candidate storage projects can reduce the need for conventional thermal generation thus resulting in cost reduction or avoided cost which is the societal benefit associated with capacity deferral. In this context, this benefit may contribute to the sustainable development in the Union.

Indicator Calculation:

- Modelling needs: accurate assessment would require a detailed modelling exercise for the monetization via investment costs of peaking units which requires further modelling activities that is beyond the scope of this report. An alternative solution without significant modelling requirements would be based on project assumptions and relative calculations.
- Data needs: Scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). If detailed modelling is introduced, extensive data requirement to simulate the whole electricity system and present the future investment needs for conventional thermal generation. In absence of extensive modelling, the benefit can be calculated based on project assumptions and relative calculations.
- How the benefit is expressed: the benefit can be expressed in monetary terms as the deferred generation investments for peak load plants and for spinning reserves. Thereby the societal benefit is monetized through avoided investments.

Link with other CBA indicators

- B1, B7, B8

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4

Notes/Double counting effects

- Capacity deferral of thermal generation is within the scope of B7 and B8 indicators, since investment into generation capacity could be driven by the need to increase the system margin (B8) or the need for the provision of flexibility and system services (B7).

Introduction

While storage units may defer the need for investment in conventional, thermal generation capacities, they are not meant to be prioritized against other technological alternatives and should be used only when appear to be a more cost-effective solution (against other solutions). In this context, the investment decisions should be based on the principal of cost effectiveness such that deploying storage technology reduces the need for other conventional technologies. The market-based socio-economic welfare assessment can assess how storage may out-compete other supply; if this reduces the viability to a point where the development of conventional generation can be deferred (without adequacy issues and a risk for security of supply), the resulting cost reduction (or avoided cost) is the societal benefit associated with capacity deferral.

For the investment costs of peaking units, figures need to be derived for the investment costs of generation units in the respective region and market area, including a forecast of the future development of these figures throughout the time span considered for PCI candidate assessment.

Calculation process

For the calculation of this benefit, the impact on the amount of generation capacity investments of peak load plants should be considered. The underlying assumption concerning the monetization of this benefit is that the candidate energy storage project will potentially allow reducing consumption and peak load and will provide additional solutions to cope with supply variability. Taken cumulatively, these effects would lead to a reduction of maximum installed capacity and consequently to a deferral of generation investments. The calculations take into account the investment cost of the marginal unit at peak and assumes that generation deferral is based on reducing peak demand. Alternatively, the monetization of generation capacity deferral can be achieved by considering the investment cost of the best new entrant peaking unit, as a benchmark for generation capacity costs. The monetised benefit related to deferred investments in generation can be calculated as follows:

*Deferred generation investments for peak load plants (€) = Annual investment to support peak load generation (€/year) * Time deferred (# of years)*

3.1.10 B10 – Transmission capacity deferral [€/a]

Indicator Definition:

- Definition: deferral and/or reduction of the investment need for grid capacity extension.
- Relevance: candidate storage projects can reduce the need for grid capacity extension thus resulting in cost reduction or avoided cost which is the societal benefit associated with transmission capacity deferral. In this context, this benefit may contribute to the sustainable development in the Union.

Indicator Calculation:

- Modelling needs: A reduction of the grid capacity need can be quantified through network studies. An alternative solution without significant modelling requirements would be based on project assumptions and relative calculations.
- Data needs: Scenarios must be compliant with TYNDP scenarios (Article 12 TEN-E Regulation). In absence of extensive modelling, the benefit can be calculated based on project assumptions and relative calculations.
- How the benefit is expressed: the benefit can be expressed in monetary terms as the deferred transmission investments for serving peak load shift and energy consumption variations. Thereby the societal benefit is monetized through avoided investments.

Link with other CBA indicators

- B1, B7

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4

Notes/ Double counting effects

- The benefit of transmission investment deferral is within the scope of indicator B6 –since system balancing energy services can either be provided by storage or by flexible generation, connected through additional transmission capacity.
- If there is a risk of double counting with other indicators like B6, these risks should be clearly identified and the share of this indicator that is already accounted in indicator B6 should be removed.
- The development of a common metric that allows for the comparison of storage and transmission projects, is advisable, in order to allow the monetisation of transmission capacity deferral via transmission investment benchmarks.

Introduction

Due to their flexible operation storage projects may reduce stress on the grid, alleviate congestion and thereby reduce the need for grid capacity extension. Thus, storage projects can potentially defer investment in transmission assets. Although the two technologies can potentially substitute each other, such that deploying one reduces the need for the other some studies have provided opposite results. For instance, Neetzow et. al [23] have used a theoretical model, to show that storage capacities and transmission grids can also be complements if electricity system costs are minimized. In these cases a storage project may increase the need for additional transmission capacity and vice versa.

Calculation process

For the calculation of this benefit several steps should be followed. First, the future incremental cost for the reinforcement of the grid due to the growing peak demand should be estimated. This implies the necessity to estimate the incremental cost per MW of peak demand [€M/ΔMW] and can be achieved by considering the planned reinforcement projects to meet growing peak demand. Projections about growing peak demand are based on the projected growth rates. These rates can be determined on the basis of historical growth, economic, social and industrial factors.

The second step is to understand the reasons of peak reduction. It is observed that peak reduction can be mainly achieved through two different ways: consumption reduction and peak load shifting.

The third step is the calculation of the benefit for both the consumption reduction and peak load shift. The benefit is calculated as a percentage of reduction on the Incremental cost per MW of peak demand. The formulas for the calculations are the following:

- Deferred transmission capacity investments due to consumption reduction:

  Value (€) = Peak demand reduction due to energy savings [MW] Incremental cost per MW of peak demand [€M/ΔMW]*

- Deferred transmission capacity investments due to peak load shift:

  Value (€) = Peak demand reduction due to peak load shift [MW] *% of networks where the peak corresponds with general peak *Incremental cost per MW of peak demand [€M/ΔMW]*

where Peak demand reduction due to energy savings [MW] = % demand reduction * peak demand * % contribution of domestic and commercial load (or whatever load-type is influenced by the project in question)

3.1.11 B11 – Variation of redispatch services [€/a]

Indicator Definition:

- Definition: Change in needed reserves of redispatch power plants thanks to the candidate storage project.
- Relevance: candidate storage projects can reduce the need for the need for reserve power plants.

Indicator Calculation:

- Modelling needs: A variation of the cost of redispatched services can be achieved with the use of redispatch simulations.
- Data needs: Availability of the annual maximum redispatch power with and without the project.
- How the benefit is expressed: the benefit can be expressed in monetary terms and can be monetised using statistical analysis of the costs of reserve from power plants, i.e., from changing capacity constraint payments.

Link with other CBA indicators

- B1, B2, B3, B4, B5

Link with specific criteria TEN-E Regulation

- Sustainability: point 3(a) of Art. 4
- Market integration: point 3(a)(i) of Art. 4
- Security of supply: point 3(a)(ii) of Art. 4

Notes

- This benefit indicator can only be calculated when applying redispatch simulations.
- The indicator is not exposed to the risk of double counting as this benefit can only be applied to projects located in countries where a specific mechanism for allocating redispatch power plants exists, and in reality the costs for allocating them must be paid independently if the respective capacity will be used or not.

Introduction

When TSOs perform redispatch activities, they adjust the active power feed-in from power plants to avoid or resolve occuring congestions. By lowering the active power feed-in of one or more power plants while at the same time increasing the active power feed-in of one or more other power plants, the total active power feed-in remains virtually unchanged, but the congestion is removed. Re-dispatch measures result in extra costs for consumers. First, when TSOs request power plants to limit their production, they have to compensate them for the power they would have been paid for supplying (minus expenses the power plants save on fuel). Second, when TSOs request renewable power producers to disconnect RES from the network, they should also be compensated for some of their lost profit. Third power plants are compensated to produce extra power, at costs higher than the market price for increasing the power feed-in.

Calculation process

For the calculation of this benefit, it is assumed that within country where the energy storage project is located, a mechanism for allocating redispatch power plants exists and that the assessment has been performed using redispatch simulations. After meeting this assumption, a few steps should be followed for the proper calculations:

First, the redispatch power with and without the project for each hour of the year should be calculated.

Second, the maximum redispatch power for both cases, with and without the project, should be detected.

Third, the difference between the maximum redispatch power for the cases with and without the project should be calculated.

Fourth, the benefit can be monetised the benefit with the use of the allocated redispatch power plan values.

3.2 Costs

The relevant costs for each year analysed in the study horizon should be provided, accompanied with assumptions on the duration of authorisation, construction time and decommissioning phases. In particular, the following cost elements shall be taken into account:

- capital expenditure costs (CAPEX);
- operational and maintenance expenditure costs;
- costs induced for the related system over the technical lifecycle of the project;
- decommissioning and waste management costs; and
- other external costs.

Project promoters shall clearly describe what cost elements are incurring within the study horizon, taking into consideration the specificities of equipment and installations constituting the pertinent candidate SGG project.

Costs occurred before the study horizon shall be actualised at using as reference year the year after the adoption of the relevant Union list of PCIs and PMIs (e.g. 2024 is the reference year for the first Union list of PCIs and PMIs under the revised TEN-E Regulation).

Member States impacted by the costs related to a candidate energy storage project should be identified and disaggregated costs at Member State level should be provided.

Information shall be provided in a format allowing the Commission to check and verify the impact of the assumptions and the relevant calculations (e.g., Excel spreadsheet). Confidentiality of sensitive information must be ensured in line with the provisions of TEN-E Regulation.

3.3 Project value calculation

The Economic Net Present Value (ENPV) represents the difference between the present value of all monetised benefits and the present value of all costs, discounted using the discount rate.

$$ENPV = \sum_{y=0}^{T} \frac{TotB_{mon,y} - TotC_{,y}}{(1+r)^y}$$

where:

- T is the study horizon;
- y represent the year within the study horizon when benefits and costs occur;
- $TotB_{mon,y}$ is the sum of monetized benefits for the y-th year;
- $TotC_y$ is the sum of total costs for the y-th year;
- r is the social discount rate;

Another indicator to be calculated is the benefit-cost ratio (BCR), which is the ratio between the present value of all monetised benefits divided by the present value of all costs[11]

$$BCR = {\sum_{y=0}^{T} \frac{TotB_{mon,y}}{(1+r)^y}} \Bigg/ {\sum_{y=0}^{T} \frac{C_y}{(1+r)^y}}$$

Benefits and costs shall be actualised at using as reference year the year after the adoption of the relevant Union list of PCIs and PMIs (e.g. 2024 is the reference year for the first Union list of PCIs and PMIs under the revised TEN-E Regulation).

3.4 Transparency and confidentiality

In submitting their CBA application, project promoters for candidate energy storage projects must provide all the necessary information with the appropriate level of transparency, also taking into consideration the provisions of the TEN-E Regulation, to allow the Commission to be able to rebuild the ENPV and BCR calculations.

Confidentiality of sensitive information must be ensured in line with the provisions of TEN-E Regulation.

(11) More detailed information on the project value calculation can be found in the latest CBA methodology developed by the ENTSOs

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List of abbreviations and definitions

ACER	European Union Agency for the Co-operation of Energy Regulators
BSPs	Balancing Service Providers
CAPEX	Capital Expenditure Cost
CBA	Cost Benefit Analysis
DAM	Day Ahead Market
EASE	European Association on Storage for Energy
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	EU Emissions Trading System
EU	European Union
GHG	Greenhouse Gases
JRC	Joint Research Centre
LoLE	Loss of Load Expectation
MC	Marginal Cost
ENPV	Economic Net Present Value
OPEX	Operational Expenditure Cost
PCI	Project of Common Interest
PMI	Project of Mutual Interest
RES	Renewable Energy Sources
SEW	Socio-economic welfare
TEN-E	Trans-European Networks for Energy
TFEU	Treaty on the Functioning of the European Union
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VoLL	Value of Lost Load
vRES	variable Renewable Energy Sources

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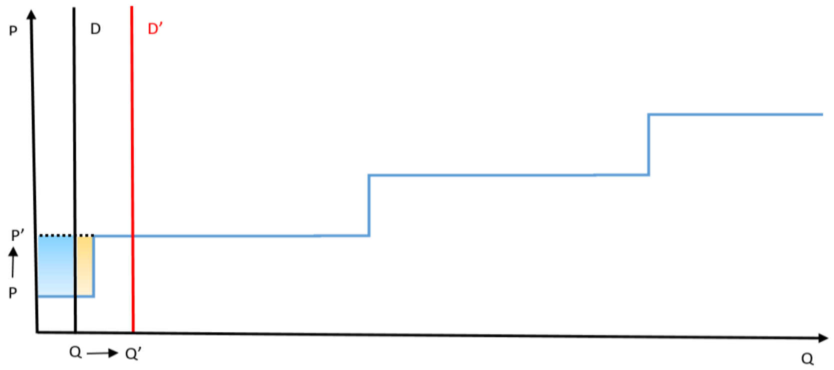
Annexe(s)

Annex 1.

We sketch out an example illustrating the fundamental logic behind the estimation of SEW benefits from storage in the simplest possible terms. For the sake of simplicity, absence of binding constraints to the availability of transmission capacity ("copper plate") will be assumed here, but the analysis can be readily extended to a context where these instead are present.

Figures 1 and 2 describe the general logic of socio-economic welfare benefits flowing from storage.

Figure 1. Storage charging impact on demand

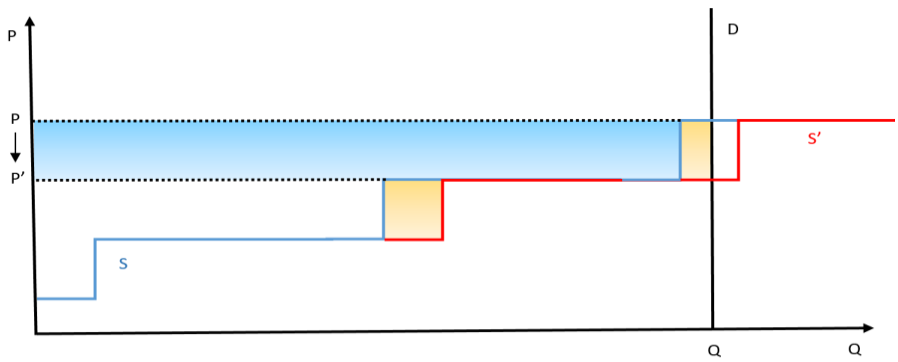


Source: Own elaboration.

Figure 1 is a Price/Quantity (P/Q) graph which depicts the effect of an increase in storage capacity shifting up load at low-demand low-price times. Merely by way of illustration, it is built assuming a vertical (i.e. perfectly inelastic) demand curve D: this equates positing that changes in prices will not lead demand to increase or decrease. Assuming a classic downward-sloping demand curve would only complicate the analysis as the key conclusions would carry over.

In Figure 1 one can see that the added demand from storage shifts the demand curve outward from D to D', so that prices are driven up from P to P', which shifts some surplus from consumers to producers (blue-shaded area), obviously due to previous consumers having to pay more for the same energy. A new flow of profits is created for low-cost generation (orange-shaded area), which is a net social welfare addition.

Figure 2. Storage discharging impact on supply



Source: Own elaboration.

We can see here above the effects of adding the same amount of storage capacity to supply at a time of high demand. The capacity expansion shifts the upward-sloping supply curve S outward by an amount equivalent to the demand curve's outward shift in the previous graph. The new supply curve S' is depicted by the red step-wise segment. This leads to prices decreasing from P to P'. Their drop shifts a large amount of social welfare from former producers' infra-marginal rents to consumer surplus (blue-shaded area). On top of this, it creates net gains in social welfare through storage's infra-marginal rents (orange-shaded area below P') and newly minted consumer surplus (orange-shaded area above P'), equivalent to the overall decrease in generation marginal costs.

The way the graphs are drawn, proving that storage can create large net gains in consumer surplus requires no more than a glance at the relative size of the shaded areas. Their wide horizontal difference brings to graphical evidence that this is precisely due to storage's key technical feature: intertemporal arbitrage allows it to buy its energy low and sell it high. One could build examples were most of the gain flows to producers instead (in case peak prices don't fall) or, on the other hand, no loss is caused to consumers (in case trough prices don't rise). Even in the case where no prices change (so that no shifts in surpluses occur), new net social welfare is created by the decrease in generation costs which is the direct feeder of storage's newly gained infra-marginal rents. The general idea is hard to miss: rationally exploited storage has the potential to significantly relieve supply constraints, right at the time when this is most needed, and this can add significant social value. Let us further point out that the gains to be made on balancing provision, hence system security, may well be as large, or even larger, than through price smoothing on the Day-Ahead Market.

Annex 2. Modification of the methodology due to the contributions received from the public consultation

1. Introduction

The consultation on the draft Energy Storage CBA methodology is part of the process for the development of methodologies for a harmonised energy system-wide cost-benefit analysis at Union level pursuant to Article 11(8) of the revised TEN-E Regulation. Concerning the Energy Storage CBA methodology, the consultation started on 7 October 2022 and ended on 6 January 2023. The consultation has been carried out through EUSurvey[12], the European Commission's official survey management tool.

The objective of this consultations was to seek input from stakeholders on the draft Energy Storage CBA methodology published on 7 October 2022. The consultation was open to the public and stakeholders, who were invited to answer questions for the overall approach of the methodology as well as questions for each individual indicator of the methodology. As it concerns the first, the public consultation included the following questions:

- In your view, to what extent does the draft methodology allow for a harmonised energy system-wide cost-benefits analysis at Union level?

- Do you have any feedback regarding the assumptions considered in the draft methodology? (Section 2.1)?

As it concerns the indicators (B1…. B10) of the methodology, the public and stakeholders were invited to answer the following three questions for each individual indicator, respectively:

- In your view, is the benefit well described in line with the legal base?

- Do you agree with the proposed method for calculating this benefit?

- Do you have suggestions for data sources which could be used for the calculation of this benefit?

2. Consultation results

Six (6) stakeholders, including three (3) project promoters, one (1) University, one (1) Transmission System Operator (TSO) and one (1) consultancy, responded to the public consultation for the development of the methodology on the Harmonised system-wide cost-benefit analysis for candidate energy storage projects The six individual stakeholders have participated in the procedure through the EU Survey channel (6 responses) as well as by submitting official letters (2 letters). Overall, the great majority of the respondents agree with the proposed methods for calculating the benefits and the description of benefit in line with the legal base. However, a significant percentage of the respondents raised concerns regarding the calculation methods of individual indicators. Table below provides the Commission's positions to the responses received via EUSurvey and official letters.

([12]) https://ec.europa.eu/eusurvey/home/about

3. Summary of changes due to input received from the public consultation

Number Comment	Respondents' comments	Outcome
1	B3 indicator is highly questionable and it has poor support from a theoretical point of view. Further, the respondent explains that this impact should be measured as power market SEW, and only as that.	B3 is a non-monetary indicator, which is mainly designed to capture the benefit of increased sustainability of the Union energy system due to the associated increase of RES and not the impact on electricity market prices and the associated SEW. On contrary B1 indicator intends to capture the impact on electricity market prices and SEW.
2	for B10 indicator, the storage and transmission lines should never be weighted out against each other and in general, a storage cannot be installed instead of a transmission line. Quite the contrary: both assets need each other.	The text has been modified by providing clarifications and references regarding the issue of substitution between transmission and storage investments: the use of storage is not meant to substitute transmission investments.
3	respondents have raised concerns regarding the double counting/overlap effect between B1 and B3 indicators as well as between B9 and B10 indicators.	In response to these suggestions relevant clarifications were provided in B1, B3, B9 and B10.
4	A respondent suggested that balancing capacity demand should be included in the calculation of B1 indicator	Balancing capacity demand is already taken into consideration in B8 as well as in B6 indicator.
5	as it concerns the input values for the monetisation of GHG, non-GHG emissions and VOLL values (B2, B4, B8 Indicators) some respondents suggested alternative sources and references	-
6	regarding B6 indicator, a respondent is considering as not appropriate to split the social economic value of meeting demand and meeting ancillary services capacity requirements.	-
7	B7 indicator, mixes a variety of ancillary services, without providing any guidance or specific references on how to calculate social economic value for a project providing these services.	Clarification were provided, while congestion management was deducted from the relevant list of services of the indicator B7 and a new indicator B11 was created.

Number Comment	Respondents’ comments	Outcome
8	To taking into account flexibility solutions and demand response in the description and calculation process of B7 indicator	This suggestion cannot be used as the future benefit from flexible demands and grid-enhancing technologies are already reflected in the decrease of the marginal cost of the equation for calculating the benefit. Also in what concerns the time horizon (future benefits) it is clear that the indicator is calculated for each year within the CBA horizon.
9	B8 indicator, should require the project promoters to take into account / differentiate between different types of storage operation.	Clarifications were provided regarding the multiple sources from where storage units can generate revenues (e.g. participation in the capacity markets by providing resource adequacy).
10	for all the indicators concerned some respondents believe that it does not make sense to have the indicator calculated by project promoters as this indicator requires a detailed modelling exercise simulating a larger portion of the electricity system beyond the project.	The text has been modified.

The summary of the impact in the indicators from the public consultation contributions is shown in the figure 3:

Indicator	Consultation Results	Actions after Consultation
B1: Socio-economic welfare in electricity markets	Major review request	Modifications implemented
B2: GHG emissions	Minor review request	Clarifications provided
B3: RES integration	Major review request	Modifications implemented
B4: Non- GHG emissions	Suggestions/ improvement request	Without changes
B5: Grid Losses	Suggestions/improvement request	Without changes
B6: Electricity balancing markets services	Minor review request	Clarifications provided
B7: Other ancillary services markets	Minor review request	Modifications implemented
B8: Adequacy to meet demand	Minor review request	Clarifications provided
B9: Generation capacity deferral	Suggestions received	Without changes
B10: Transmission capacity deferral	Suggestions received	Clarifications provided

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