3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects

Draft version

28 January 2020

I. Foreword

This document presents the third version of the ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (short: 3rd CBA guideline).

This new guideline is the result of 'learning by implementing' and taking into account stakeholder suggestions over a five-year development process. During this period, Member States and National Regulators were consulted and the guideline submitted to the official opinion of the Agency for Cooperation of Energy Regulators (ACER) and of the European Commission (EC).

The Regulation (EC) 347/2013 mandates that ENTSO-E drafts the European Cost Benefit Analysis (CBA) guideline, which shall be further used for the assessment of the Ten-Year Network Development portfolio. The first official CBA guideline drafted by ENTSO-E was approved and published by the European Commission on 5 February 2015, the second official CBA guideline drafted by ENTSO-E was approved by the European Commission on 27 September 2018 and published by ENTSO-E on 11 October 2018.

The first edition of the CBA guideline was used by ENTSO-E to assess projects in the ten-year network development plan (TYNDP) 2014 and 2016. ENTSO-E registered the impact of the TYNDP project assessment results on the European Commission Projects of Common Interest (EC PCI) process. This experience proved the need of a better guideline that allows a more consistent and comprehensive assessment of pan-European transmission and storage projects.

The 2nd CBA guideline has a more general approach than its predecessor and assumes that the project selection and definition, along with the scenario's description, is within the frame of the TYNDP and, therefore, not defined in the assessment guideline in detail. With this approach, ENTSO-E aims to develop a CBA guideline that can be used for one TYNDP as well as include strong principles that will stand for a longer time. The 2nd CBA guideline has been used by ENTSO-E to assess project benefits in the TYNDP 2018. However, although improvements were included in the 2nd CBA guideline, some so called 'missing benefits' where added to the TYNDP 2018 in addition to what is defined in the 2nd CBA guideline. This, together with the constant effort of ENTSO-E to improve the CBA guideline, highlighted the need to establish a 3rd version of the CBA guideline. The 3rd CBA guideline exhibits improved methodologies for already existing indicators and an introduction to new indicators. Among these, some new indicators stem from the lessons learnt from the 'Missing Benefits' process that was established for TYNDP 2018; however, the complexity of some of these new indicators does not allow for a Pan-European assessment. For this reason, the 3rd CBA guideline includes new 'project level indicators' the nature of which will be clarified in Chapter 3.4.

Why is the 3rd CBA guideline important?

- This CBA guideline is the only European guideline that consistently allows the assessment of TYNDP transmission and storage projects across Europe.
- The outcomes of the CBA guideline represent the main input for the European Commission Project of Common Interest list.
- The European CBA guideline could also be used as a source for national CBAs.

II. Table of Contents

1 Introduction

This Guideline for Cost Benefit Analysis of Grid Development Projects was prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E) in compliance with the requirements of the EU Regulation (EU) 347/2013 (referred to as 'the Regulation').

This guideline is the third such version of the document produced by ENTSO-E (referred to as the 3rd CBA guideline) and was the result of an extensive consultation process. The consultation process involved the public, stakeholder organisations, national authorities and their national regulatory authorities, the Agency for Cooperation of Energy Regulators (ACER), and the European Commission (EC).

The indicators that have been developed allow for a harmonised, system-wide cost-benefit analysis of projects. They facilitate a uniform approach in which all projects (including storage and transmission projects) and promoters (either TSO or third party) are treated and assessed in the same way.

The guideline's primary use is to describe the projects contained in the ENTSO-E 10-year Transmission Network Development Plan (TYNDP), including the Projects of Common Interest (PCI) that are identified from the list of TYNDP projects. It is also recommended to be used for the cross border cost allocation (CBCA) process, as required by the Regulation (Article 12(a)).

The analysis techniques and methodologies developed in this guideline are of general relevance to the electricity industry and may therefore also be of use to anyone seeking to assess transmission investments because it provides a comprehensive and rigorous structure within which to undertake a cost benefit analysis.A number of indicators were developed to meet the specific requirements of the Regulation with respect to market integration, security of supply, and sustainability, including the integration of renewable energy and energy storage, among others. Of particular reference, the indicators are designed to comply with Article 4.2, Article 11, Annex IV, and Annex V of the Regulation.

The rapid development of renewable energy sources (RES) and the liberalisation of the European electricity market has resulted in increasingly inter-dependent power-flows across Europe, with large and correlated variations. Transmission system design, therefore, needs to be broadened from a national focus to consider regional and European solutions. Close co-operation between the ENTSO-E member companies responsible for the future development of the European transmission system is essential to achieve coherent and co-ordinated planning at such a level.

- In the context of the TYNDP, one objective of transmission system planning is the development of an adequate pan-European transmission system that enables the safe operation of the grid, a high level of security of supply, and the exchange of power between countries. It should facilitate grid access to all market participants; and contribute to a sustainable energy supply, competition, internal market harmonisation and integration; and the energy efficiency of the pan-European system.

The transmission system planning process takes into account the national legislation and regulatory frameworks, the general regulations of the liberalised European power and electricity market per European Union (EU) legislation, and EU policies and targets. It seeks to ensure the preservation of the security of people and infrastructure and compliance with environmental policies in a transparent and economically efficient manner.

1.1 Scope of the document

Transmission system development focuses on the long-term preparation and scheduling of reinforcements and extensions to the existing transmission grid. The identification of an investment need is followed by the project promoter(s) defining a project that addresses this need. The aim of the 3rd CBA guideline is to deliver a general guideline on how to assess projects from a cost and benefit point of view.

This guideline, therefore, sets out the ENTSO-E criteria for the assessment of costs and benefits of projects. It describes the common principles and methodologies to be used in the necessary network studies, market analyses, and inter-linked modelling methodologies. It is because of this general approach, allowing for the application to different studies, that not all study specific details and requirements can be described in detail within the scope of this document. In addition to the 3rd CBA guideline, a study specific complementary implementation guideline needs to be published along with the respective study, containing all relevant input data, data sources, and assumptions utilised during CBA implementation. An overview of the required supplements, defined within the implementation guideline for the TYNDP, is given in the end of Section 6.3.

A multi-criteria approach is used to describe the indicators associated with each project. To ensure a full assessment of all transmission benefits, some of the indicators are monetised, whereas others are quantified in their typical physical units (i.e. tons or GWh). The set of common indicators contained in this guideline form a complete and solid basis for project assessment across Europe, both within the scope of the TYNDP as well as for project portfolio development in the PCI selection process.[1]

The 3rd CBA guideline also applies to the assessment of storage projects. In principle, storage projects are to be assessed in a similar way to transmission projects, even though their benefits can be considered more closely related to ancillary services.

The preparation of the cost-benefit analysis of projects takes place in the context of the TYNDP process. As part of the TYNDP process, ENTSO-E develops scenarios that describe how the future energy landscape is to function within the transmission system. This is in compliance with the Regulation, which requires projects to be assessed under different planning scenarios, each of which represents a possible future development of the energy system. Whilst project costs are scenario independent the benefits strongly correlate with scenario-specific assumptions. Therefore, scenarios that define potential future developments of the energy system are used to gain insight into the future benefits of transmission projects.

[1] It should be noted that the TYNDP does not select PCI projects. Regulation (EU) 347/2013 (art4.2.4) states that 'each Group shall determine its assessment method on the basis of the aggregated contribution to the criteria […] this assessment shall lead to a ranking of projects for internal use of the Group. Neither the regional list nor the Union list shall contain any ranking, nor shall the ranking be used for any subsequent purpose.'

A system-needs assessment determines the impact of those scenarios on the transmission system, identifying network bottlenecks and additional investment needs. This requires network power-flow, stability, and market analyses. Project assessments, using the 3rd CBA guideline, identify how the transmission and storage projects will contribute to the future power system. An overview of the process is illustrated in Figure 1: Overview of the assessment process inside the TYNDP and for identifying PCIs.

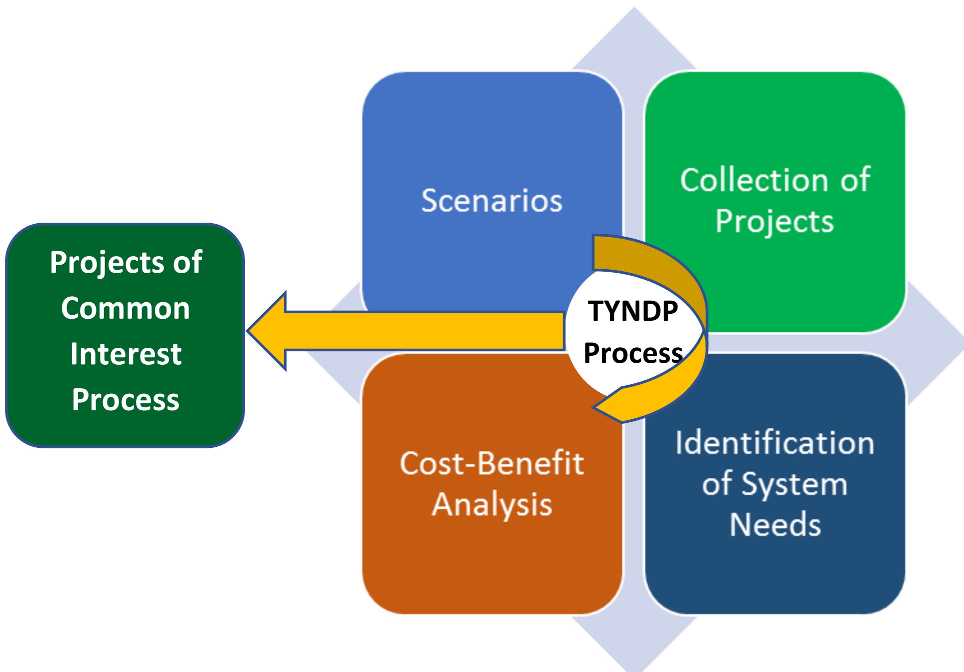


Figure 1: Overview of the assessment process inside the TYNDP and for identifying PCIs

This is a continuously evolving process; therefore, this document will be reviewed periodically, in line with prudent planning practice and further editions of the TYNDP, or upon request (as foreseen by Article 11 of the Regulation).

1.2 Overview of the document

The 3rd CBA guideline is the first version of the guideline to be constructed using a modular approach. The purpose of the modular approach is to enable more efficient updates of the guideline by allowing stakeholders to better focus on specific content without necessarily impacting the whole document.

To enable the modular approach, the 3rd CBA guideline is structured as five main chapters that are supported by a number of separate and detailed sections. The sections are used to provide a full description of the indicator. They discuss the methodology to be used and describe the principles and requirements to properly assess the relevant indicator. The application for the TYNDP is further supported with supplemental implementation guidelines that are to be provided separately.

Chapter 1 provides an introduction to the guideline and provides a context to the indicators that have been developed for use in cost benefit analysis.

Chapter 2 discusses general approach matters. This includes, among others, a discussion regarding scenarios and study horizons, cross-border and internal projects, reference network descriptions, and sensitivities.

A detailed description of the overall assessment, including the modelling assumptions and indicator structure, is given in Chapter 3. A general overview of the indicators is given in Section 3.3. This set of common indicators forms a complete and solid basis for project assessment across Europe, both within the scope of the TYNDP and for project portfolio development in the PCI selection process.[2]

Chapter 4 addresses the assessment of storage projects. The main assumptions and methodologies used for transmission projects can also be applied to the assessment of storage. However, a special guideline is included in the chapter to cover the unique properties of storage.

A conclusion is contained in Chapter 5, and provides a summary of the intention of the 3rd CBA guideline.

The benefit indicators, costs description and residual impacts are in detail described in Chapter 6, starting with an overview of the used definitions and abbreviations. Additionally the details of the main concepts are also explained in this section.

[2] It should be noted that the TYNDP does not select PCI projects. Regulation (EU) 347/2013 (art4.2.4) states that 'each Group shall determine its assessment method on the basis of the aggregated contribution to the criteria […] this assessment shall lead to a ranking of projects for internal use of the Group. Neither the regional list nor the Union list shall contain any ranking, nor shall the ranking be used for any subsequent purpose.'

2 General approach

The general approach used to assess projects takes the following into account:

- The range of future energy scenarios and study horizons.
- Internal and cross-border considerations.
- The modelling framework and the acceptable techniques to be used in undertaking the analysis.
- The identification of a reference network that is used to assess the impact of the reinforcement against.
- The use of multi-case analysis to simplify analysis.
- The approach to sensitivity studies.

These are discussed in detail below.

2.1 Scenarios

Scenarios are constructed at the level of the European electricity system and can be adapted in more detail at a regional level. When constructed in order to reflect European and national legislation, they have to reflect the respective legislation in force at the time of the analysis and their effect on the development of these elements.

Scenarios are a description of plausible futures that can be characterised by: a **generation portfolio**; a **demand forecast;** and power **exchange patterns** between the study region and other power systems. The scenarios represent a means of addressing future uncertainties and the interactions between those uncertainties. The objective of using scenario analysis is to construct sufficiently contrasting future developments that differ enough from each other to capture a plausible range of possible futures that result in different challenges for the grid. These different future developments can be used as input parameter sets for subsequent simulations.

Scenarios are the basis for further calculation of the grid's development needs. All projects included in the TYNDP must be assessed against the same set of scenarios (provided that the project is assessed for the given reference year).

All analyses of TYNDP projects are based on the scenarios developed by ENTSO-E. These scenarios provide the framework within which the future is likely to occur, but does not attach a probability of occurrence to them. Some TYNDP scenarios have a stronger national focus than others; some are 'top-down' whereas others are 'bottom-up'. There is no right or wrong, likely or unlikely option; all scenarios have to be treated equally and, because of the uncertainties of the future energy sector, no scenario can be defined as a 'leading scenario'.

These scenarios aim to provide stakeholders in the European electricity market with an overview of generation, demand, and their adequacy in different scenarios for the future ENTSO-E power system, with a focus on power balance, margins, energy indicators, and generation mix.

The scenarios are elaborated after formally consulting Member States and the organisations representing all relevant stakeholders.

2.2 Study horizons

Scenarios can be distinguished depending on the time horizon, as illustrated in Figure 2, and can be described as follows:

- Mid-term horizon (typically 5 to 10 years): mid-term analyses should be based on a forecast for this time horizon.
- Long-term horizon (typically 10 to 20 years): long-term analyses will be systematically assessed and should be based on common ENTSO-E scenarios.
- Horizons which are not covered by separate data sets will be described through interpolation or extrapolation techniques.

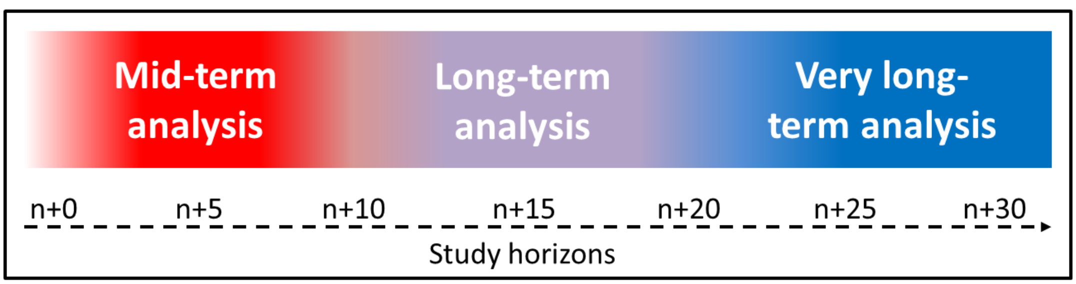


Figure 2: Time horizons: continuous timeline with future study years and corresponding study horizons: mid-term (red), long-term (purple), and very long-term (blue).[3]

As shown in Figure 2, the scenarios developed for the long-term perspective may be used as a bridge between the mid-term horizon and the very long-term horizon (i.e., n+20 to n+40). The aim of the perspectives beyond n+20 should be that the pathway realised in the future should fall within the range described by the scenarios with a reasonable level of likelihood.

The scenarios on which to conduct the assessment of the projects will be given for fixed years and rounded to full five years (e.g., 2025 instead of 2023 for n+5 in TYNDP 2018). For the mid-term

[3] There is no strict definition of the beginning and end of the horizons and an overlap might appear, indicated by the gradual colour gradients used in the figure.

horizon, the scenarios must be representative of at least two study years. For example, for the TYNDP 2020, the study years of the mid-term horizon are 2025 (n+5) and 2030 (n+10).

2.3 Cross-border versus internal projects

The assessment of projects using only the impact on the transfer capacities across certain international borders can lead to an underestimation of the project-specific benefits. This is due to the fact that most projects also show significant positive benefits that cannot be covered by only increasing the capacities of a certain border. This effect is the strongest for, but not limited to, internal projects.

Internal projects do not necessarily have a significant impact on cross-border capacities, which makes it difficult to assess them using market simulations that consider only one node per country, if not using a flow based model.

Both internal and cross-border projects can be classified as having pan-European relevance. However, they all develop grid transfer capability (GTC) over a certain boundary, which may, or may not, be an international border (and sometimes several boundaries).

Depending on the types of project, a suitable method should be used. At this point it is recognised that there is no unified method available that can address the specific aspects of all these projects adequately. Therefore, three alternative methods are given for the calculation of the benefits:

- Market simulations
- Network simulations
- Combined market and network simulations, i.e., redispatch simulations

Both market and network simulations provide different types of information; they generally complement one another so are often used in an iterative manner. These methods are discussed in detail in the following Chapter.

2.4 Modelling framework

As the indicators described in Section 6 generally rely on different principles, they also need to be achieved under the use of different models. An overview of these models, i.e., **Market simulations**, **Network simulations,** and **Redispatch simulations**, is given in this section.

It should be noted that most of the indicators can be achieved using more than one of the described models; this information will be given in an overview table at the end of the respective indicator.

Market simulations

Market simulations are used to calculate the cost-optimal dispatch of generation units. This is done under the constraint that the demand for electricity is fulfilled, taking demand-side response (DSR) into account, in each bidding area and in every modelled time step.[4] In addition to the dispatch of generation and demand (if modelled endogenously), market simulations also compute the market exchanges between bidding areas and corresponding marginal costs for every time step.

The simulations take into account several constraints, such as:

- The flexibility and availability of thermal generating units;
- Hydrology conditions impacting hydro generating units;
- Wind and solar generation profiles;
- Load profiles; and
- The occurrence of outages.

Market simulations are used to determine the benefits of providing additional capacity, enabling more efficient use of the generation units available in the different locations across the bidding areas. They facilitate the measurement of savings in generation costs because of the investments in grid and/or storage projects. The results of market simulations, therefore, enable the computation of some of the indicators specified in this guideline.

The output of market simulations are used to define the generation, consumption, and power flowing across the transmission grid as an input to the network simulations.

Different options represent the transmission network in market models, namely:

- **Net transfer capacity (NTC)-based market simulations**

  Bidding areas are represented as a network of interconnected nodes, connected by a transport capacity that is available for market exchanges using a simplified (NTC) model of the physical grid. These NTC values represent an approximation of the potential for market exchanges using the physical (direct or indirect[5]) interconnections that exist between each pair of bidding areas. Thus, the market studies analyse the cost-optimal generation pattern for every time step under the assumption of perfect competition.

- **Flow-based simulations**

  Flow-based market simulations combine market and network studies. They consider the inter-relation between the power-flow obtained from network simulations and the corresponding

[4] Typically, market simulations apply a one-hour time step, which is in accordance with the time step used in most electricity wholesale markets. However, this CBA guideline is independent from the chosen time step.

[5] In general, the market flow is different from the corresponding physical flow, as getting the trading capacities e.g., ring flows, do not need to be considered. The important information is the trading capacity between two markets.

potential for market exchanges. Flow-based market simulations take into account the relationships between each potential market exchange and their corresponding utilisation of the physical grid capacities (cross-border as well as internal grid). Flow-based market simulations, therefore, use a representation of physical grid capacities to define the market exchange constraints, rather than a set of independent NTC values.

- **Network simulations**

  Network simulations make use of models that represent the transmission network in a high level of detail. They are used to calculate the power flowing on the transmission network for a given generation-load-market exchange condition. Network simulations allow bottlenecks in the grid corresponding to the power-flows resulting from the market exchanges to be identified.

  The results of the network simulations allow the computation of some of the indicators contained in this guideline.

- **Redispatch simulations**

  Redispatch simulations compute the costs of alleviating constraints on the transmission network, identified by network simulations taken from market simulations, by adjusting the initial dispatch of generation. This is done while observing the same power plant specific constraints that applied to the market simulations, such as the minimum up- and down-times, ramp rates, must-run obligations, variable costs, etc. Redispatch simulations can, therefore, be seen as a combination of both network and market simulations.

Redispatch simulations assist in the computation of indicators contained in this guideline. They particularly relate to the evaluation of projects using the initial generation dispatch from NTC-based market simulations as a starting point.

More details on how to perform redispatch calculations are provided in 6.21 Section 21: Redispatch simulations for project assessment.

2.5 Reference network

The reference network is the version of the network that is used to calculate the incremental contribution of the project that is assessed. Therefore, it is used as the starting point for the computation of cost and benefit indicators.

The reference network is made up of the existing grid and the projects that have a strong chance of being implemented by the dates considered in the scenarios.

To determine the incremental contribution of each project, market and network simulations are performed in which the project is either included in the reference grid or removed from it. The results are then compared with the market and network simulations of the reference grid alone. The incremental benefit would be the difference between the two results and these are reflected in the indicators contained in this guideline.

The selection of the projects that comprise the reference network directly impact the calculation of the indicators. As a result, a clear explanation of which projects are taken into account in the reference network is required. This should also include an explanation of the initial state of the grid (i.e., the existing grid as defined in the year of the study).

A project should only be included in the reference grid when its capacity is available in the year for which a simulation is performed. Hence, only those projects whose timely commissioning is reasonably certain are to be included in the reference network. This can be assessed by considering the development status of the project and including the most mature projects that are either:

a) In the construction phase; or

b) In 'permitting' or 'planned, but not yet permitting', and their timely realisation is most likely (e.g., when the project is supported by country-specific legal requirements or the permitting and construction phase can be assumed to be short, such as for transformers). This requirement can be strengthened by applying further criteria, such as:

    - The project is considered in the National Development Plan of the country where it is expected to be located.
    - The project fulfils the legal requirements as stated in the specific national framework where the project is expected to be located.
    - The project has a defined position with respect to the Final Investment Decision related to its implementation.
    - There is a documented reference to the environmental impact assessment.
    - There is a documented reference to the request for permits.
    - A clearly defined system need, to which a project contributes, could help to identify the reference grid.
    - Year of commissioning: chosen depending on the year of the study and the scenario horizon used to perform the study.

Whatever criteria has been chosen, the proof of maturity needs to be given in the study following the guideline given in the respective implementation guidelines.

In cases where a cross-border project involves countries with different permitting processes and procedures it would be advisable to use expert evidence-based judgement.

The impact of the scenario that is used should also be reflected in the reference network as different scenarios use different assumptions, which would impact differently on the expected capacities. The reference network, therefore, reflects the assumptions made by the scenarios.

Whenever the year of the CBA's first mid-term horizon-study-year exactly corresponds to the mid-term study year of the Mid-Term Adequacy Forecast study, it is required that the scenarios used and the corresponding reference grids are consistent (taking into account the possible data modifications due to the different timelines of the studies).To obtain the NTC value for the reference network, the NTC increases of each single, non-competing project must be taken into account. In some cases, the calculated NTC increase (from the previous TYNDP, if the project was already included) should not simply be added to the present NTC values, but expert judgement is needed to correctly account for the increases.

Multi-case analysis

System planning simulations are carried out using the results of market simulations as an input. The network simulations produce load flow calculations for each time step for which the market simulations produce their results, typically hourly.

In order to simplify the volume of network calculations, network simulations may group results from several time steps into one planning case. This can only be done if the hours that are grouped together are similar enough in terms of the generation dispatch, load dispatch, and market exchange within the area under consideration. These results for each planning case are then considered as representative for all the time steps that are linked to it.

It is crucial that the choice of planning cases and the time steps that they represent are adequate, i.e., that the planning cases selected out of the available cases for each time step adequately represent the year-round effect. The process of obtaining a representative set of planning cases depends greatly on the combination of dispatch, load, exchange profiles, and especially on the availability profiles for variable renewable energy sources.

2.6 Sensitivities

Sensitivity analysis can be performed to observe how the variation of parameters, either one parameter or a set of interlinked parameters, affects the model results. This provides a deeper understanding of the system's behaviour with respect to the chosen parameter or interlinked parameters.

In principle, each individual model parameter can be used for a sensitivity analysis, but not all might be equally useful to obtain the desired information. Furthermore, different parameters can have a different impact on the results, depending on the scenario, therefore, it is recommended to perform detailed scenario-specific studies to determine the most impacting parameters.

Based on the experience of previous TYNDPs, the parameters listed below could optionally be used to perform sensitivity studies. This list is not exhaustive and provides some examples of useful sensitivities within the boundaries of the scenario storylines.

- **Fuel and CO_2-Price**

  A global set of values for fuel prices is defined as part of the scenario development process. A degree of uncertainty regarding these values and prices is unavoidable. Fuel and CO_2-prices determine the specific costs of conventional power plants and, thus, the merit order. Therefore, varying fuel and CO_2-prices impact the merit order, which in turn have an impact on the related indicators that are required to be reported on as part of this guideline.

- **Long-term societal cost of CO_2 emissions**

  The cost of CO_2 that is included in the generation costs may understate (or overstate) the full long-term societal value of avoiding CO_2. Therefore, a sensitivity study could be performed in which the cost of CO_2 is valued at a long-term societal price. To perform this sensitivity without introducing any risk of double-counting with the generation cost indicator, the following process is advised:

  a) Derive the delta volume of CO_2;

  b) Consider the CO_2 price internalised in the generation cost indicator;

  c) Adopt a long-term societal price of CO_2.

  By multiplying the volume arising from (a) by the difference in prices described by (b) and (c), the monetisation of the sensitivity of an increased value of CO_2 can be calculated.

  For this sensitivity there is no adjustment in the merit order or the dispatch for the generation cost indicator for the higher carbon price. If such an exercise is to be performed, it would represent a full re-run of the indicator against the different data assumption of a higher forecast carbon price included in the generation background and merit order.

- **Climate year**

  Using historical climate data from different years might influence the benefits of a project. For example, the indicator RES-integration depends on the infeed of RES and weather conditions. For this reason, performing analysis with different climate years would lead to a deeper understanding of how market results depend on weather conditions. This can be used to understand how the indicators are impacted by climatic conditions.

- **Load**

  Regarding the development of load, two opposed drivers can be identified. On the one hand, energy efficiency will lead to decreasing load, but on the other hand, an increasing number of applications will be electrified (e.g., e-mobility, heat pumps, etc.), which will lead to an increase in load. **Technology phase-out/phase-in**

Due to external circumstances, a phase-out/phase-in of a specific technology (e.g., nuclear or lignite) could occur and lead to a transition of the whole energy system within a member state. Such developments cannot be foreseen and are not considered within the scenario framework and can therefore be treated within sensitivity studies.

- **Must-run**

  If thermal power plants provide electrical power and heat, then thermal power ‘must-run’ boundary conditions are used in market simulations, i.e., these power plants cannot be shut down and have to operate in specific time frames, and at a minimum level, in order to ensure heat production. By assuming different must-run conditions for conventional power plants, market results will differ.

- **RES installed capacity**

  The volume of installed RES capacity is defined for each scenario. Sensitivity studies in which the installed RES capacity is varied could be performed to assess the impact of a delay or an advancement of RES capacity delivery on the indicators contained in this guideline.

It has to be noted that interdependencies between the above listed sensitivities can occur, e.g. the variation in CO_2 costs will in general also have an impact on the installed generation units. However, as a robust investigation on these interdependencies can become very complex. This goes beyond the single treatment of sensitivities as addition to the CBA assessment and can instead be treated within specific studies.

3 Project assessment: combined cost-benefit and multi-criteria analysis

This chapter discusses the approach to be taken in the assessment of projects. It establishes a methodology for the clustering of investments into projects,[6] defines each of the cost and benefit indicators, and the project assessment required for each indicator.

The goal of a project assessment is to characterise the impact of a project, both in terms of added value for society as well as in terms of costs.

The assessment of costs and benefits are undertaken using a multi-criteria approach within which both qualitative assessments and quantified, monetised assessments are included. In such a way, the costs and benefits are represented, highlighting the characteristics of a project and providing sufficient information to decision makers. Such an approach recognises that a fully monetised approach is not practically feasible in this context as many benefits cannot be economically quantified in an objective manner. Examples of such benefits include system safety and environmental impact.

The multi-criteria analysis approach is capable of supporting a comparison of those costs and benefits that can be monetised in the form of a conventional cost-benefit analysis, while recognising that other material benefits also exist that are not quantified.

3.1 Multi-criteria assessment

The overall assessment of projects is displayed as a combined cost-benefit and multi-criteria matrix in the TYNDP. A general overview is discussed and illustrated in Chapter 3.3. Most indicators associated with the costs and benefits indicators are monetised and displayed in Euros. Other indicators are displayed using a calculated value in the most relevant and appropriate units of measure.

Using this combined cost-benefit and multi-criteria assessment, each project is characterised by its impact on both the added value for society and in terms of costs in a standardised way. Therefore, the overall impact, positive or negative, for each project can be compared.

By considering all of the indicators described by the multi-criteria approach, comprising both monetised and un-monetised, the full benefit of a project can be described. This approach recognises that the importance of each indicator might be project specific, i.e., the main aim of one project might be to significantly integrate large amounts of RES into the grid, whereas the main focus of another project may be an increase in the security of supply by means of connecting highly flexible generation units. In both cases, the monetised benefits (determined by the monetised indicators) may be the key driving indictors for making an investment decision, but they may not be the only ones.

Figure 3 displays a simplified overview of the entire project assessment process resulting in the set of CBA market and network indicators that are described in this guideline.

[6] In general, a project can consist of only one investment. Obviously in this case no clustering rule has to be applied.

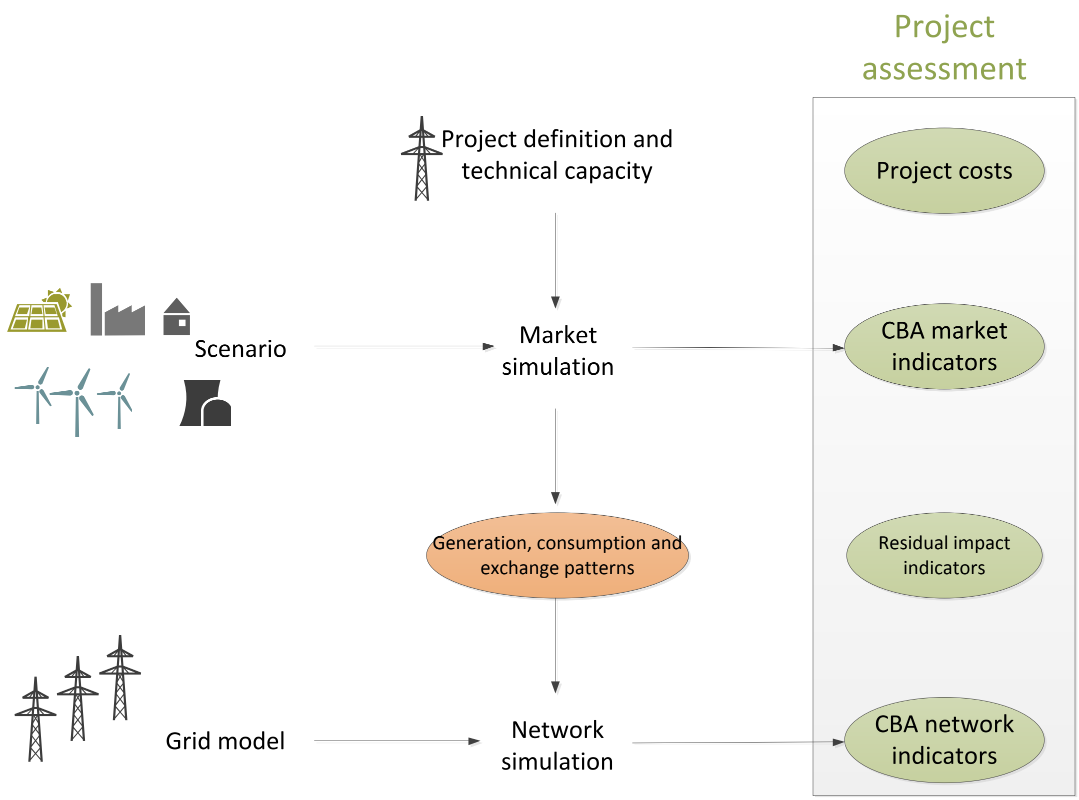


Figure 3: Schematic project assessment process. While 'CBA market indicators' and 'CBA network indicators' are the direct outcome of market and network studies,[7] respectively, 'project costs' (see 6.14 and 6.15) and 'residual impacts' (see 6.18, 0 and 6.19) are obtained without the use of simulations.

3.2 General assumptions

This sub-chapter provides a general guidance on the assessment of projects. It provides guidelines for the clustering of investment, the computation of transfer capability, the consideration of geographic scope, and the calculation of a net-present value on the basis of the (monetised) indicators.

3.2.1 Clustering of investments

In some cases, a group of investments may be necessary to develop transmission capacities (i.e., one investment cannot perform its intended function without the realisation of another investment). This process is referred to as the clustering of investments. In this case, the project assessment is done for the combined set of clustered investments.

[7] The information is given for each indicator, if an indicator is calculated using market studies, network studies, or a mixture of both, in the section dedicated to that indicator.

When investments are clustered, it must be clearly demonstrated why this is necessary. Investments should only be clustered together if an investment contributes to the realisation of the full potential of another (main) investment. Investments that contribute only marginally to the full potential of the main investment will not be clustered together.

The full potential of the main investment represents its maximum transmission capacity in normal operation conditions. When clustering investments, one main investment (e.g., an interconnector) must explicitly be defined, which is supported by one or more supporting investments. A project that consists of more than one investment is defined as a main investment with one or more supporting investments attached to it.

Note that competing investments cannot be clustered together.

Further limitations are as follows:

- Investments can only be clustered if they are at maximum of one stage of maturity apart from each other. This limiting criterion is introduced in order to avoid excessive clustering of investments that do not contribute to realising the same function because they are commissioned too far ahead in time.

- If an investment is significantly delayed[8] compared to the previous TYNDP, it can no longer be clustered within this project. In order to avoid a situation whereby investments are clustered when they are commissioned far apart in time (which would also introduce a risk that one or more investments in the project are never realised), a limiting criterion is introduced that prohibits clustering of investments that are more than one status away.

Figure 4 illustrates the categories of investments and which investments may be clustered. The categories marked in green in each row can be clustered. For example, a main investment with status 'permitting' can either be clustered together with investments that are 'planned, but not yet in permitting' (second row) or 'under construction' (third row).

Under consideration	Planned, but not yet in permitting	Permitting	Under construction

Figure 4: Illustration of the clustering of investments

[8] Where the term 'significant delay' has to be seen as case-specific, in relation to all investments in that project, the investment with the earliest commissioning date might be delayed further, compared to that of the latest commissioning date.

3.2.2 TOOT AND PINT

There are two methods that are used to assess a project's performance. These are illustrated in Figure 5 and are described as follows:

- **Take Out One at the Time (TOOT) method**:

  The reference network represents a future target network in which all additional network capacity is assumed to be in place (compared to the starting situation). The projects under assessment are then removed from the future target network, one at a time, to evaluate the changes to each of the indicators.

- **Put IN one at the Time (PINT) method**:

  The reference network represents the initial state of the network without the projects under assessment. The projects under assessment are then added to the reference network, one at a time, to evaluate the changes to each of the indicators.

Projects that are 'under consideration' are seen as non-mature and, therefore, have to be excluded from the reference grid. These projects are assessed using the PINT approach, regardless of their position in respect to any additional criteria.

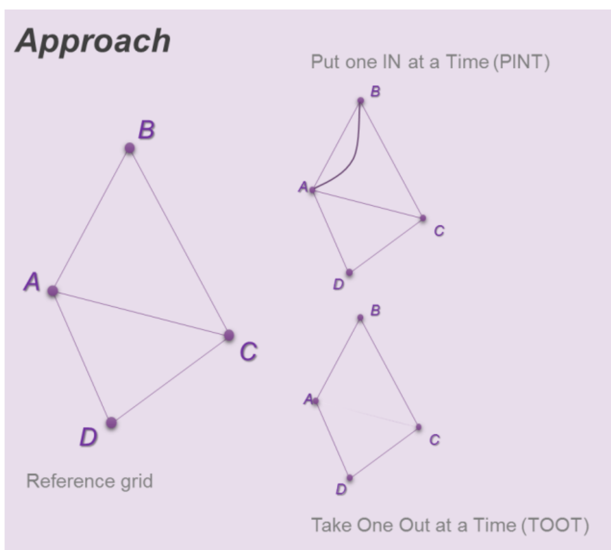


Figure 5: Illustration of TOOT and PINT approaches

The TOOT and PINT methods are to be applied consistently for both market and network simulations.

The TOOT method provides an estimate of the benefits for each project, as if it were the last to be commissioned; i.e., it is evaluated as part of the whole forecasted network. The advantage of this analysis is that every benefit brought by each project is assessed together, without considering the order of projects. Hence, this method facilitates assessment at the aggregated TYNDP level, with the future power system and the evolution of every future network being considered.

For the PINT method, the reference network is clearly defined by the network model that is used; for market simulations the reference network takes into account the exchange capacities between the defined market zones, including the additional capacity brought by the projects included in the grid. The PINT assessment is then applied 'on top' of all projects assessed using the TOOT methodology and thus provide an estimation of benefits for each project as if it were commissioned after all TOOT projects, but the first and only one to be commissioned compared to all PINT projects.

In general, application of the TOOT approach has the potential to underestimate the benefits of projects because all project benefits are calculated under the assumption that the project is the final (marginal) project to be realised. On the other hand, application of the PINT approach has the potential to overestimate the benefit of projects (compared to all other PINT projects) because all of the projects' benefits are calculated under the assumption that the project is the first project to be realised (after all TOOT projects have been realised). Project benefits are generally, but not necessarily always, negatively affected by the presence of other projects (i.e., if one project is built, a second one will have lower benefits). This effect is generally strongest when two (or more) projects are constructed to achieve a common goal across the same boundary, although it may also be present when projects are constructed along different boundaries.

Multiple applications of TOOT/PINT

For interdependent projects, strict application of the TOOT or PINT methods may not fully reflect the benefits of the projects. Therefore, in addition to the project benefits calculated using the strict application of the TOOT or PINT methods, the benefits arising from the realisation of other projects on the same boundary can be calculated (i.e., multiple TOOT or PINT). When the multiple TOOT or PINT methods (or a combination of both) are applied, a detailed description of the sequence of projects must be given.

It should be noted that the reference for the second, third, etc. project in the sequence of the multiple TOOT/PINT needs to be taken correspondingly. While the first project in the sequence can be assessed and compared against the reference grid (no change compared to the TOOT/PINT method as described above), the reference for the second project should be such that the first project has been taken out (for TOOT) or put in (for PINT). The third project needs to be assessed against the situation as defined by the second step and so on.

Example for three interdependent TOOT projects:

Project number	Commissioning date
1	2021
2	2022
3	2024

- project 3: assessment against the reference grid by taking the project out.
- project 2: assessment against the situation with project 3 already taken out.
- project 1: assessment against the situation with project 3 and project 2 already taken out.

3.2.3 Transfer capability calculation

There are two concepts of transfer capability that guidelines refer to, namely: **Net Transfer Capacity** and **Grid Transfer Capacity**. Net Transfer Capacity is related to the potential for market exchanges of electricity resulting in a power shift of dispatch from one bidding zone to another, and Grid Transfer Capacity is related to physical power-flows that can be accommodated by the grid.

Net Transfer Capacity (NTC)

The **NTC** reflects the ability of the grid to accommodate a market exchange between two neighbouring bidding areas. An increase in NTC (ΔNTC) can be interpreted as an increased ability for the market to commercially exchange power, i.e., to shift power generation from one area to another (or similarly for load). The physical power-flow that is the result of this power shift may or may not directly flow across the border of the two neighbouring bidding areas in its entirety, but may or may not transit through third countries. The increase in the ability to accommodate market exchanges as a result of increasing physical transmission capacity may, therefore, be different from the capability of the grid to transport physical power across the border.

As the exchanges between bidding zones result in power-flows making use of the transport capacity across the different boundaries they impact, an increase in GTC across a specific boundary is illustrative, *ceteris paribus*,[9] of the increased exchange capability between these bidding zones.

Note that while the concept of NTC calculations in the context of long-term studies is similar to the operational calculation of NTC values on borders, the concept of NTC, as defined for the purpose of long-term planning studies, may show some differences in the sense that the approaches may not consider the

[9] 'Ceteris paribus' acknowledges that in actual system operations, one single boundary is not exclusively influenced by only the exchanges between the bidding zones it relates to. The physical flow on the boundary can also be influenced by exchanges between other bidding zones which, for example, cause loop or transit flows. These influences are not taken into account when calculating the increased NTC delivered by a project in the context of this methodology.

same operational considerations to ensure a safe and reliable operation of the system. The NTC values reported in long-term studies are calculated under the 'ceteris paribus' assumption that nothing else in the system changes (e.g., generation and load in neighbouring zones, RES fluctuations, loop flows) and, therefore, does not have an impact on the calculated power shift made possible by the project (i.e., which equals market exchange). In the TYNDP, the assumed utilisation of the additional grid transfer capability delivered by a project will be reported in terms of ability for additional commercial exchanges (i.e., ΔNTC) between the bidding zones that define the boundary in question. Note that the ΔNTC is directional, which means that values might be different in either direction of the commercial power-flow across a boundary.

ΔNTC is calculated using network models by applying a generation power shift[10] across the boundary under consideration. This figure applies to the year-round situation (i.e., 8,760 hours) of how the generation power shift affects the power-flow across the boundary under analysis. Calculating an ΔNTC value generally results in a different value for each simulated time step of the year under consideration. This year-round situation should be reflected in the load flow analysis either via a simulation of each individual time step or via a simulation of a set of points in time that are representative of the year-round situation. The annual delta NTC that is reported corresponds to the 70th percentile of the delta NTC duration curve (i.e., the value is reached for at least 30% of the year). This is illustrated in Figure 6. In case the reference NTCs used in the market simulations are time-dependent (e.g., seasonal values are used), the calculated delta NTCs could also be time-dependent, e.g., obtaining a different value for each season, rather than a single annual NTC.

[10] It should be mentioned that the methodology on how the generation power-shift is applied can have a significant impact on the results and must be clearly explained in the respective study. A consistent approach for the generation power shift must be applied for all assessments. The power shift method(s) are to be defined in the Implementation Guideline and reported on the project sheets.

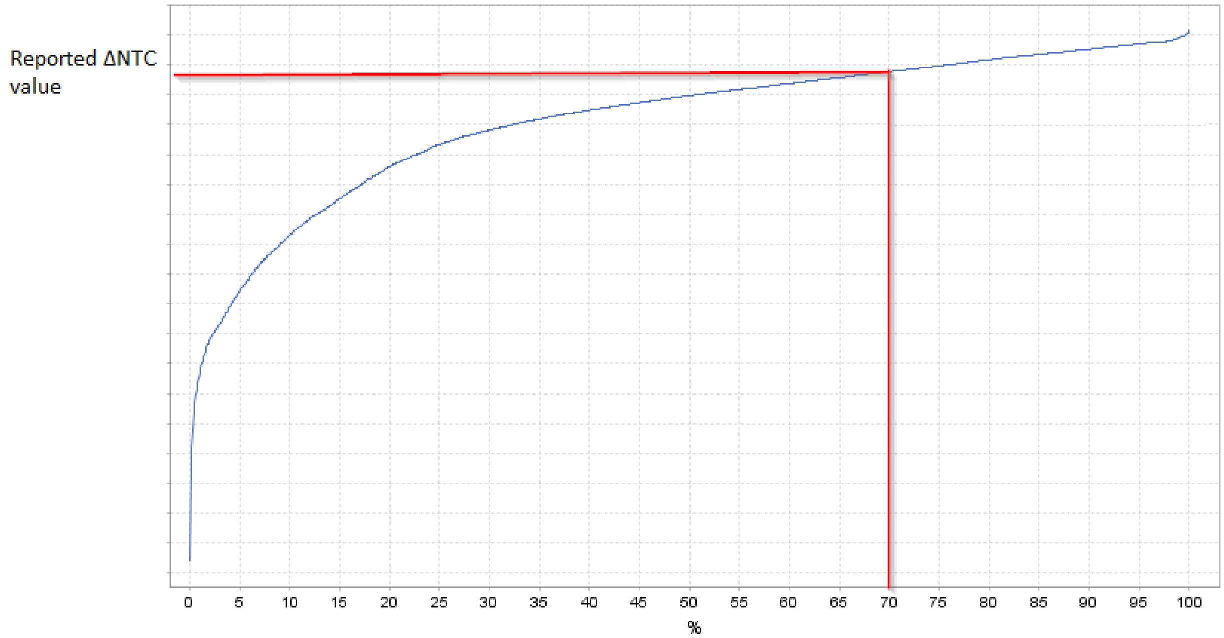


Figure 6: Duration curve of ΔNTC in one direction (blue) with 70th percentile (red): the reported ΔNTC at the 70th percentile needs to be reached at least 30% of the time –to the right of the red line.

The calculation of the ΔNTC is based upon a reference network model in line with the scenario considered. As ΔNTC is the result of the possible power shift, the figure may differ between scenarios.

A detailed example of how the ΔNTC on one time step can be calculated is given in the implementation guideline for the respective TYNDP.

Grid Transfer Capacity (GTC)

The **GTC** reflects the ability of the grid to transport physical electricity across a boundary in compliance with relevant operational standards for safe system operation. A boundary usually represents a bottleneck in the power system where the transfer capability is insufficient to accommodate the power-flows (resulting from the dispatch of power plants and load, depending on the scenario under consideration) that will need to cross them. A boundary may be fixed (e.g., a border between countries, bidding areas or any other relevant cross-border) or vary from one study horizon or scenario to another.

The distribution of power-flows across a boundary, and by consequence also the GTC, depends on the considered state of consumption, generation, and exchange, as well as the topology and availability of the grid and accounts for safety rules. Therefore, the contribution of a project in developing transport capacity across a boundary (ΔGTC) is dependent on the scenario that is being evaluated. It is calculated by performing network simulations using the year-round market results as an input and identifying the power-flow across the boundary corresponding to the situation where (at least) one of the critical branches relevant for the given boundary (which may not be limited to the circuits that make up the boundary itself) is loaded at 100% of its thermal capacity. This is illustrated in Figure 7, where the project increases the GTC across the boundary XY in the direction from X to Y from 400 MW to 1,000 MW, therefore, the project delivers a ΔGTC of 600 MW.

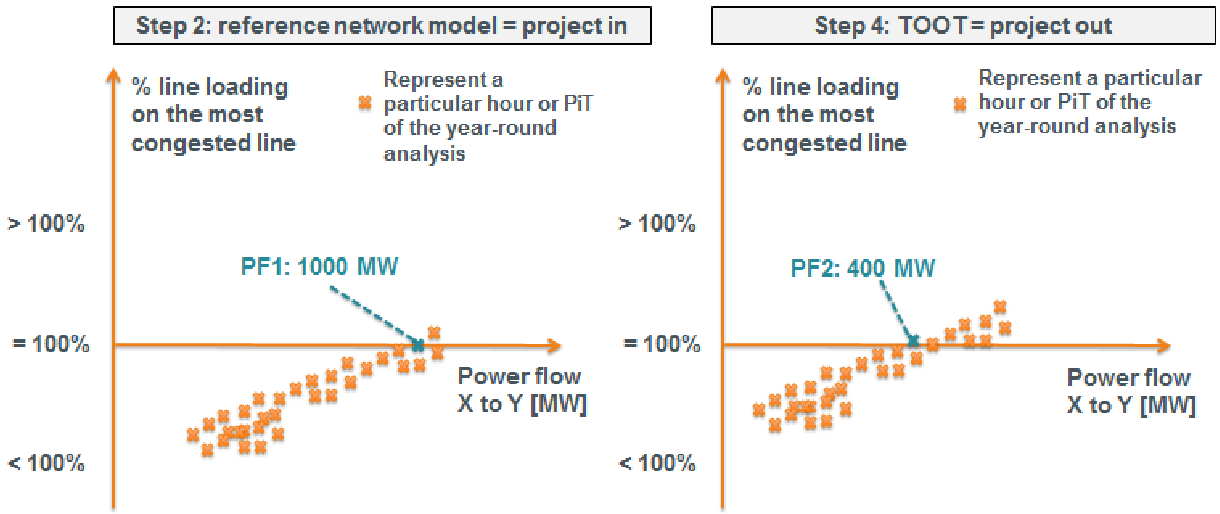


Figure 7: Schematic illustrating the calculation of ΔGTC

The additional GTC can be used for accommodating additional physical flows across a boundary that are the result of increased market exchanges between directly neighbouring bidding areas; increased transit flows resulting from market exchanges between other European countries; and/or increased loop flows. Each of these flows are the result of changes in the dispatch and/or load pattern in the system and, therefore, facilitate the market.

Reporting on transfer capability

The impact on transfer capability must be reported on at the investment level for each project. This means that the reporting must be done for each investment and also for the project as a whole. In the case of a project with a cross-border impact, the figures to be reported are the ΔNTC of the project and the contribution of the investment(s). For an internal project either ΔNTC or ΔGTC must be reported[11]. In any case, for each project it must be clearly displayed whether a cross-border transfer capacity, an internal transfer capacity, or a combination of both types of transfer capacities is provided.

The method that is used to perform the generation power shift has to be reported in the respective study and the same method must be applied in a clear and consistent way for all projects that are under assessment.

[11] In case an internal project has a cross-border impact, the ΔNTC values have to be reported.

3.2.4 Geographical scope

The main principle of system modelling is to use detailed information within the studied area and a decreasing level of detail outside the studied area. As a minimum requirement, the study area should cover all Member States and third countries on whose territory the project shall be built, all directly neighbouring Member States, and all other Member States significantly impacted by the project.[12] In order to take into account the interaction of the pan-European modelled system in the market studies, exchange conditions with non-modelled countries will be fixed for each of the simulation time steps based on a global market simulation.[13] Practically, the market model should cover all European countries, plus any third countries that host the assessed project. For network analysis, each synchronous zone that is relevant for the project should be modelled (generally, this means the synchronous zone in which the project is located; for HVDC projects between different synchronous areas, all synchronous areas should be modelled, except for third countries).

Project appraisal is based on analyses of the global (European) increase of welfare.[14] This means that the goal is to bring up the projects that are best for the European power system.

3.2.5 Guidelines for investment value calculation

The value of an investment is calculated using the discounted cash flow method. This method takes into account the timing of costs and benefits and recognises that the value of money changes over time, which is often referred to as the time value of money. The assumption is that the value of money changes at a constant annual rate, referred to as the discount rate. The future values of both costs and benefits can then be represented (or discounted) to present values using the discount rate.

The present value (PV) of a future cost or benefit (referred to as FV) in a given time period *n*, using a discount rate of *r* per annum, is described by the following formula:

$$PV_n = \frac{FV_n}{(1+r)^n}$$

The main methods that are used to represent the value of an investment as a single value are Net Present Value (NPV) and Benefit-to-Cost Ratio (BCR). Both of the methods assess the viability of the investment and where there are a number of competing investments it is used to facilitate a comparison of competing investments where consistent assumptions are applied.

[12] Annex V, §10 Regulation (EU) 347/2013

[13] Within ENTSO-E, this global simulation would be based on a pan-European market data base.

[14] Some benefits (socio-economic welfare, CO_2…) may also be disaggregated on a smaller geographical scale, like a member state or a TSO area. This is mainly useful in the perspective of cost allocation and should be calculated on a case by case basis, taking into account the larger variability of results across scenarios when calculating benefits related to smaller areas. In any cost allocation, due regard should be paid to compensation moneys paid under ITC (which is article 13 of Regulation 714 (see also Section 23: Impact on market for caveats on Market Power and cost allocation).

The NPV of an investment is the difference between the present value of benefits (i.e., cash inflows) and the present value of costs (i.e., cash outflows) over the economic life of the investment. A viable investment is usually indicated by a positive NPV, i.e., the present value of benefits is greater than the present value of costs.

The NPV of the investment assessed over the assessment period of T years is described by the following formula:

$$NPV = \sum_{t=0}^{T} \frac{Benefit_t - Cost_t}{(1+r)^t}$$

The BCR of an investment is the ratio of the present value of benefits to the present value of costs. A viable investment is usually indicated by a BCR that is greater than one, i.e., the present value of benefits is greater than the present value of costs.

The BCR of the investment is calculated over the assessment period of T years using the following formula:

$$BCR = \frac{\sum_{t=0}^{T} \frac{Benefit_t}{(1+r)^t}}{\sum_{t=0}^{T} \frac{Cost_t}{(1+r)^t}}$$

To enable the consistent calculation of either the NPV or BCR for an investment, a consistent set of assumptions must be applied. Given that both methods use the same calculations to determine the present value of benefits and costs, the assumptions apply equally to both methods.

The key assumptions are as follows:

The assessment period defines the period of time that the investment will be evaluated. This may be different to the useful life of the investment's assets and represents the period over which it is reasonable, given the uncertainty, to expect value to be attributed to the investment. For the purposes of this guideline, the assessment period is 25 years.[15]

Values are represented as real and constant values. This means that no inflation is taken into account and, therefore, no forecasts for future inflation are necessary. It also means that values are taken as fixed throughout the assessment by assuming constant year-of-study values. The year-of-study is taken as the year of the TYNDP, i.e., 2020 for the TYNDP 2020. The impact of taxation is not considered in the project assessments so the values are to be represented as pre-tax values.

[15] In case conditions related to the context of economic assessment require, the duration of the assessment period could be reviewed in the Implementation Guidelines.

The discount rate used to calculate the NPV can differ between countries; however, for a fair assessment across projects, a common unique discount rate is required. For the purposes of this guideline, the discount rate should be given as a real value. The real discount rate to be used is 4% per annum.[16]

Future values are to be discounted to a common point in time, which is the year of the TYNDP, also referred to as the year-of-study above.

The forecasted costs and benefits for each investment are to be represented annually.

The year of commissioning is the year that the investment is expected to come into first operation.

It is generally recommended to study at least two horizons: one mid-term and one long-term horizon (see Chapter 2.2).

The inception costs are to be aggregated and represented in the commissioning year of the investment as a single value.

Further capital costs that are incurred to sustain the investment during its lifetime are to be represented in real and constant year-of-study values in the year that they occur.

The benefits are accounted for from the first year after commissioning. To evaluate projects on a common basis, benefits should be aggregated across the years as follows:

- For years from year of commissioning (i.e., the start of benefits) to the first mid-term: extend the first mid-term benefits backwards.
- For years between different mid-term, long-term, and very long-term (if any): linearly interpolate benefits between the time horizons.
- For years beyond the farthest time horizon: maintain benefits of this farthest time horizon.

For the assessment of a project that is comprised of multiple investments, the annualised benefits, losses and operational costs for each investment is accounted for from the same notional year. The notional year is the simple average of the earliest and latest investments that comprise the project.

The residual value of the project at the end of the assessment period should be treated as having zero value.

[16] In case conditions related to the context of economic assessment require, the real discount rate could be reviewed in the Implementation Guidelines.

3.3 Assessment framework

The assessment framework describes the structure used to differentiate the range of indicators that comprise the project assessment.

The assessment framework comprises three main categories made up of costs, benefits, and residual impacts, as illustrated in Figure 8: Overview of the main categories of CBA indicators. Within each of the three categories, there are a number of separate and distinct indicators that together represent the category. The composition of each of the categories is described in detail in the supporting section: 6.3 Section 3: Main project assessment categories.

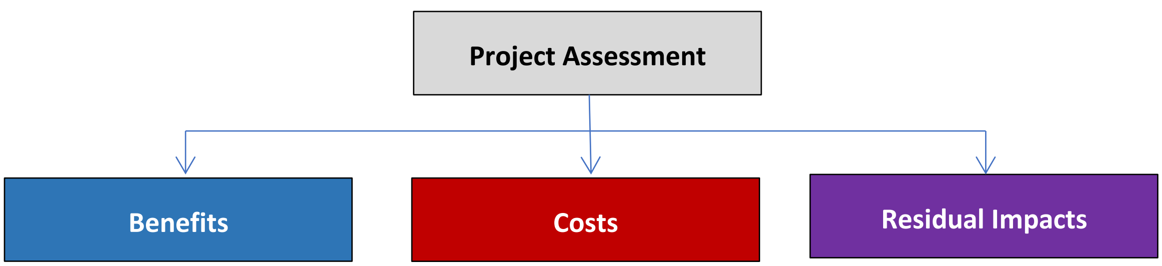


Figure 8: Overview of the main categories of CBA indicators

The assessment framework is consistent with Article 11 and Annexes IV and V of the Regulation.

Benefits describe the positive contributions made by the project. The formalised indicators that comprise the benefits are supported by detailed methodologies that are captured in their corresponding supporting sections in this guideline. Note that projects may also have a negative impact on some benefit indicators, in which case negative benefits are reported.

Costs describe the inception cost of the project or investment, i.e., CAPEX and the operating costs that incurred throughout the investment's lifecycle, i.e., OPEX. The CAPEX cost typically refers to the inception cost of the project and would also include the costs of implementing mitigation measures that address environmental and social constraints.

Residual impacts describe the impacts of investments that are not addressed by any of the identified mitigation measures that are contained within the cost category (typically as CAPEX). This ensures that all measurable costs associated with projects or investments are taken into account, and that no double-accounting occurs between any of the indicators.

3.4 Project level assessment

In some instances, there are costs or benefits that are relevant for a cost-benefit analysis, but it is not possible for ENTSO-E to assess them at a pan-European level within the TYNDP process. These are introduced in this 3rd CBA guideline as project level indicators and are fully addressed in the supporting sections. The guideline provides a clear definition of the project level indicators, describes a clear perimeter of application, and a methodology that must be followed in order to properly assess them. This is described in 6.26 Section 26: Project level assessment based on promoters' input.

Although the Pan-European nature of these indicators is recognised, it is acceptable to assess them relying on a regional, or even national, perimeter to deal with their inherent complexity (e.g., the use of a redispatch approach).[17]

Competent project promoters can submit the project level indicators within the TYNDP process until such time that the ENTSO-E's TYNDP processes are able to include them as part of its Pan-European assessment. It should be noted that the submission of project level indicators does not guarantee their inclusion as they may be assessed and determined to be not valid. The validity of the project level benefit will be verified by ENTSO-E during a review process as part of the wider TYNDP process.

[17] It is currently not possible for ENTSO-E to perform redispatch simulations in a centralised way within the TYNDP. Therefore, all redispatch calculations must be seen as 'Project level' indicators.

4 Assessment of storage

The assessment of storage can be done by making use of the CBA indicators used for the assessment of reinforcement projects. This is described in 6.20 Section 20: Assessment of Storage Projects. The principles and methodologies described in this document are also applicable for the evaluation of centralised[18] storage devices on transmission systems. This is applicable to both storage systems planned by TSOs and those planned by private promoters, even if a distinction should be made between the different roles and operational uses of the two types. This recognises that installing storage plants on the transmission grid by TSOs supports the objective of improving and preserving system security and guaranteeing cost-effective network operation without impacting internal market mechanisms or market behaviour.

Storage plants can be easily introduced in market studies as existing facilities of this type are already modelled. Hence it can take into account some of the functional constraints and deviations that occur between stored and retrieved energies.

Business models for storage are often categorised by the nature of the main target service, distinguishing between a deregulated-driven business model (i.e., income from activities in electricity markets) and a regulated-driven business model (i.e., income from regulated services). The analysis described in this guideline will not be able to account for these differences.[19] If project promoters have methodologies available that allow them to differentiate between the two cases, they should use and document them clearly. For transmission, the analysis will yield monetised benefits of storage using a perfect market assumption (i.e., including perfect foresight) and account for non-monetised benefits using the most relevant physical indicators.

The impact of storage projects can be evaluated as a contribution to the improvement of security of supply, the capacity for trading of energy and balancing services between bidding areas, RES integration, losses and CO_2 emissions, adequacy, flexibility, and power system stability.

[18] At least 225 MW and 250 GWh/year as defined by the published EC Regulation (EU) No 347/2013

[19] It should be noted that following the regulatory systems, the owners of storage will not be likely to capture the full value of storage. Hence, in some countries, a TSO owner will not be able to capture any arbitrage value, whereas a private owner will not be able to capture any system service value.

5 Concluding remarks

This guideline for the cost-benefit analysis of grid development projects was prepared by ENTSO-E in compliance with the requirements of the EU Regulation (EU) 347/2013. This guideline is the third such version of the document produced by ENTSO-E and was the result of an extensive consultation process.

The document is a general guide to assist in the assessment of planned projects that are included in ENTSO-E's Ten Year Network Development Plan. It describes the common principles and procedures for performing the analysis of costs and benefits for projects using network and market simulation methodologies. Following Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure, it also serves as the basis for a harmonised assessment of PCIs at the European Union level.

A multi-criteria approach is used to describe the indicators associated with each project. To ensure a full assessment of all transmission benefits, some of the indicators are monetised, whereas others are quantified in their typical physical units (i.e., tons or GWh). The set of common indicators contained in this guideline form a complete and solid basis for project assessment across Europe, both within the scope of the TYNDP as well as for project portfolio development in the PCI selection process.

The guideline also applies to the assessment of storage projects. In principle, storage projects are to be assessed in a similar way to transmission projects, even though their benefits can be considered more closely related to ancillary services.

This third CBA guideline is the first version of the guideline to be constructed using a modular approach. The purpose of the modular approach is to enable more efficient updates of the guideline by allowing stakeholders to better focus on specific content without necessarily impacting the whole document. This recognises that the guideline is an evolving and living document that we endeavour to continually improve to meet the needs of our stakeholders.

6 Sections

6.1 Section 1: General definitions

Boundary

A boundary represents a barrier to power exchange in Europe. It represents a section (transmission corridor) within the grid where the capacity to transport the power-flow related to the (targeted level of) power exchange in Europe is insufficient.

In this context, a boundary is referred to as a section through the grid in general. A boundary can:

- Be the border between two bidding zones or countries;
- Span multiple borders between multiple bidding zones or countries; or
- Be located inside a bidding zone or country, dividing the area into two or multiple sub-areas.

Competing transmission projects/investments

Two or more transmission projects are regarded as competing if they serve the same purpose.

In cases where competing projects are proposed to achieve a transmission capacity increase, the projects would typically (but not exclusively):

a) Increase NTC on the same boundary; and

b) Their socio-economic viability would be reduce if assessed under the assumption that the other project is also realised. Therefore, the overall net benefit of realising both projects is lower than the sum of the individual net benefits.

Current grid (starting grid)

The current grid is the existing transmission grid and is determined at a specific date that is dependent on the point in time of the respective study. It can also be seen as the starting point or initial state of building the reference grid by including the most probable projects as described in this 3rd CBA guideline.

Generation power shift

Generation power-shift is the deviation from the cost-optimal power plant dispatch (determined by market simulations) for the purpose of influencing grid utilisation.[20] Considering the loading of a line across a boundary that separates System A from System B (with energy transported from A to B), arrived at as a result of optimum dispatch,: Generation is incrementally increased in area A and decreased in area B. This process is carried out up to the point where the line loading security criteria in System A or System B is reached. The volume of the power shift represents the additional market exchange that is possible between these systems and should be reflected by the variation in NTC that is assumed in market simulations. Generation power shift is used to modify the market exchange across a specified boundary in order to find the maximum change in generation made possible by the grid.

Grid Transfer

The GTC is defined as the greatest (physical) power-flow that can be transported across a

[20] This can also be seen as the definition of the re-dispatch. To avoid confusion in this case it is referred to generation power-shift as in reality the re-dispatch is used to reduce the grid utilisation and to heal congestions. However, as described in this guideline, the re-dispatch will also be used to determine the theoretical maximum grid utilisation by bringing the system to the edge of security.

Capacity (GTC)	boundary without the occurrence of grid congestions, taking into account standard system security criteria.
Investment	An investment is the smallest set of assets that together can be used to transmit electrical power and that effectively add transmission infrastructure capacity. An example of an investment is a new circuit, the necessary terminal equipment, and any associated transformers.
Investment need	The need to develop capacity across a boundary is referred to as an investment need. As different scenarios may result in different power flows, the amount of capacity required to transport these power flows across a boundary and, consequently, the amount of investment needed, is likely to differ from scenario to scenario.
Investment status	The investment status is defined depending on its stage of development, according to one of the following six options: • **Under consideration**: Investments in the phase of planning studies and under consideration for inclusion in national plan(s) and Regional/EU-wide Ten-Year Network Development Plans (TYNDPs) of ENTSO-E. • **Planned, but not yet in permitting**: Investments that have been included in the national development plan and have completed the initial studies phase (e.g., completed pre-feasibility or feasibility study), but have not initiated the permitting application yet. • **Permitting**: Investments for which the project promoters have applied for the first permit required for its implementation and the application is valid. • **Under construction:** The investment is in its construction phase. • **Commissioned:** Investments that have come into first operation. • **Cancelled**.
Main investment	In the case of a project that consists of a number of investments, one investment (e.g., an interconnector) is to be defined as a main investment with one or more supporting investments attached to it. This is required when clustering investments. The main investment is planned to achieve the specific goal, e.g., an interconnector between two bidding areas, with the supporting investments (as part of the project) required to achieve the full potential of that main investment. The full potential of the main investment represents its maximum transmission capacity in normal operation conditions.
Net Transfer Capacity (NTC)	The Net Transfer Capacity (NTC) is the maximum foreseen magnitudes of power exchange programmes that can be operated between two bidding zones while respecting the system security requirements of the areas involved. The NTC is used in market modelling to represent the power exchange capability between bidding zones.
Planning cases	The representation of how the power system (i.e., the generation and transmission system) could be managed at a point in time. They are used to represent a detailed model of the grid for that point in time, or a snapshot, and are used in network studies. Planning cases are selected *inter alia* based on: a) The outputs from market studies, such as system dispatch, frequency, and magnitude of constraints;

b) Regional considerations, such as wind and solar profiles or cold/heat spells; and

c) Results of pan-European Power Transfer Distribution Factor (PTDF) analysis, when available.

Project

A project is defined as a single investment or group of investments. Therefore, It can comprise a main investment with supporting investments that must be realised together in order to make it possible for the main investment to realise its intended goal, i.e., the full potential that is defined as the capacity increase of the main investment. In cases where there are no supporting investments, the project consists of the main investment alone and will nonetheless be described as a 'project' in this CBA guideline.

Put IN one at the Time (PINT)

A methodology that considers each new investment/project (line, substation, phase shifting transformer (PST), or other transmission network device) on the given network structure one-by-one and evaluates the load flows over the lines with and without the examined network investment/project reinforcement.

Reference network

The reference network is the version of the network that is used to calculate the incremental contribution of the project that is assessed. Therefore, it is used as the starting point for the computation of cost and benefit indicators.

Respective study

The study in which the CBA assessment is performed, e.g., the TYNDP.

Scenario

A set of assumptions for modelling purposes related to a possible future situation in which certain conditions regarding demand, installed generation capacity, infrastructures, fuel prices, and global context occur.

Societal cost of CO_2

The societal cost of carbon can represent two concepts:

- The social cost that represents the total net damage of an extra metric ton of CO_2 emissions due to the associated climate change.[21]
- 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.[22]

Take Out One at the Time (TOOT)

A methodology that consists of excluding projects from the forecasted network structure on a one-by-one basis in order to compare the system performance with and without the project under assessment.

Ten-Year Network Development Plan (TYNDP)

The European Union-wide report examining the development requirements for the next ten years, carried out by ENTSO-E every other year as part of its regulatory obligations that are defined under Article 8, paragraph 10 of the Regulation (EU) 2019/943.

Time step

Simulation models compute their results at a given temporal level of detail. This temporal level of detail is referred to as the time step. Smaller time steps generally increase simulation run time, whereas larger time steps decrease simulation run time. Typically,

[21] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2

[22] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2

simulations are done using hourly time steps, but this level of granularity may vary depending on the level of detail required in the results.

6.2 Section 2: Abbreviations

The following list shows abbreviations used in the 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects:

ΔNTC	Increase in NTC
AC	Alternating Current
ACER	European Union Agency for the Co-operation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
BCR	Benefit-to-Cost Ratio
CAPEX	Capital Expenditure Cost
CBA	Cost-Benefit Analysis
CBCA	Cross Border Cost Allocation
CE	Continental Europe
CEER	Council of European Energy Regulators
CF	Complexity Factor
CIGRE	Council on Large Electric Systems
CONE	Cost of New Entrant
DA	Day-ahead Market
DC	Direct Current
DSR	Demand Side Response
EC	European Commission
EBGL	Electricity Balancing Guideline
EENS	Expected Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ENS	Energy Not Served
EPRI	Electric Power Research Institute
ETS	Emissions Trading Scheme

EU	European Union
FCR	Frequency Containment Reserve
FE	Frequency Exchange
FO	Frequency Optimisation
FN	Frequency Netting
FRR	Frequency Restoration Reserve
FV	Future Value (Cost or Benefit)
GTC	Grid Transfer Capability
HHI	Herfindahl Hirschman Index
HVDC	High Voltage DC
ID	Intraday Market
IPS	Integrated Power System
ITC	Inter Transmission System Operator Compensation for Transits
KPI	Key Performance Indicator
LFC	Load Frequency Control
LOLE	Loss of Load Expectation
mFRR	Manual Frequency Restoration Reserve
MS	Market Simulation
MSC	Mechanically Switched Capacitors
MSR	Mechanically Switched Reactors
NPV	Net Present Value
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OHL	Overhead Line
OPEX	Operating Expenditure Cost
P2G	Power-to-Gas

PCI	Projects of Common Interest
PINT	Put IN one at the Time
PP	Project Promoter
PST	Phase Shifting Transformer
PTDF	Power Transfer Distribution Factor
PV	Present Value
RD	Redispatch
RES	Renewable Energy Sources
ROCOF	Rate of Change of Frequency
RR	Replacement Reserves
RSI	Residual Supply Index
SA	Sychronous Area
SA-OA	Synchronous Area Operational Agreements
SEA	Strategic Environmental Assessment
SEW	Socio-Economic Welfare
SMC	Submarine Cable
SOC	System Operations Committee
SOGL	Commission Regulation (EU) 2017/1485: Establishing a Guideline on Electricity Transmission System Operation
SoS	Security of Supply
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
TOOT	Take Out One at the Time
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UGC	Underground Cable

UPS	Unified Power System of Russia
VOLL	Value of Lost Load
VSC	Voltage Source Converter
XB	Crossborder

6.3 Section 3: Main project assessment categories

The project assessment is carried out using the benefit, cost, and residual impact indicators described in this guideline. Although the benefits should be given for each study scenario (e.g., the TYNDP scenarios), costs and residual impacts are seen as scenario independent indicators.

The main project assessment categories are illustrated in Figure 9:

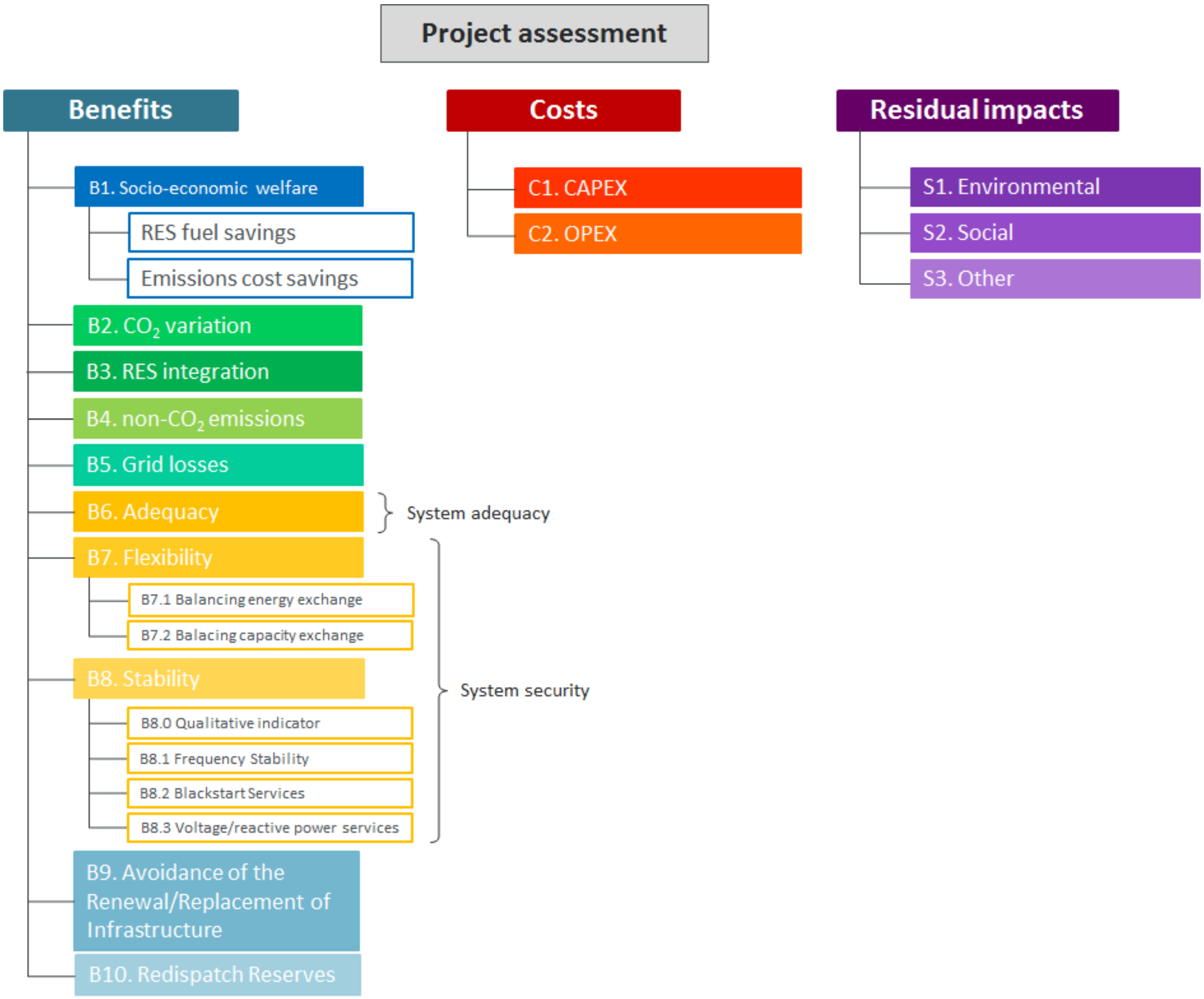


Figure 9: Illustration of the project assessment framework categories

The indicators have been selected on the following bases:

- They facilitate the description of the project costs and benefits in terms of the EU network objectives. These EU network objectives are: to ensure the development of a single European grid, enabling EU climate policy and sustainability objectives (i.e., RES, energy efficiency, CO_2); to guarantee security of supply; to complete the internal energy market, especially through a contribution to increased socio-economic welfare; and to ensure system stability.

- They provide a measurement of a project's costs and feasibility (especially environmentally and socially, as indicated by the residual impact indicators).

- They are as simple and robust as possible. This facilitates simplified methodologies where it is practical to do so.

The project assessment should reflect the average transfer capacity contribution of the project. The contribution to transfer capacity is time and scenario dependent, but a single or seasonal value should be reported for clarity reasons. A characterisation of a project is provided through an assessment of the directional ΔNTC increase and the impact on the level of electricity interconnection, relative to the installed production capacity in the Member State.[23] For those countries that have not reached the minimum interconnection ratio, as defined by the European Commission, each project must report the contribution to achieve this minimum threshold.

The increased transfer capacity contribution and costs are given per investment, whereas the benefit indicators and residual impact indicators are provided at the project level.

The **benefit** indicators are described as follows:

B1. **Socio-economic welfare (SEW from wholesale energy market integration),**[24] in the context of transmission network development, is the sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners. The indicator reflects the contribution of the project or investment to increasing transmission capacity, making an increase in commercial exchanges possible so that electricity markets can trade power in a more economically efficient manner. It is characterised by the ability of a project or investment to reduce (economic or physical) congestion.

B2. **Additional societal benefit due to CO_2 variation** is the change in CO_2 emissions produced by the power system due to the project. It is a consequence of changes in generation dispatch and the unlocking of renewable generation potential. This indicator is directly linked to the EU's climate policy goal of reducing greenhouse gas emissions by at least 40% by 2030, relative to

[23] The Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action establishes, in article 23 (a), that '…the level of electricity interconnectivity that the Member State aims for in 2030 in consideration of the electricity interconnection target for 2030 of at least 15 % …'

[24] The reduction of congestions is an indicator of social and economic welfare assuming equitable distribution of benefits under the goal of the European Union to develop an integrated market (perfect market assumption). The SEW indicator focuses on the short-run marginal costs.

1990 levels. As CO_2 emissions are the main greenhouse gas produced by the electricity sector, they are displayed as a separate indicator.

B3. **RES integration** defines the ability of the power system to connect new RES generation, unlock existing and future 'renewable' generation, and minimise the curtailment of electricity produced from RES.[25] The RES integration indicator is linked to the EU 2030 goal of increasing the share of RES to 32% of overall energy consumption.

B4. **Non-direct greenhouse emissions** refer to the change in non-CO_2 emissions (e.g., CO_X, NO_X, SO_X, PM 2, 5, 10) in the power system due to the project. They are a consequence of changes in generation dispatch and the unlocking of renewable generation potential.

B5. **Grid losses** in the transmission grid is the cost of compensating for thermal losses in the power system due to the project. It is an indicator of energy efficiency[26] and is expressed as a cost in euros per year.

B6. **Security of supply: Adequacy** characterises the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period of time. Variability of climatic effects on demand and RES production is taken into account.

B7. **Security of supply: Flexibility** characterises the impact of the project on the ability to exchange balancing energy in the context of high penetration levels of non-dispatchable electricity generation. Balancing energy refers to products such as Replacement Reserve (RR), manual Frequency Regulation Reserve (mRR), and automatic Frequency Regulation Reserve (aFRR). Exchanging/sharing balancing capacity (i.e., RR, mFRR and aFRR) that requires guaranteed or reserved cross-zonal capacity is also taken into account.

B8. **Security of supply: Stability** characterises the project's impact on the ability of a power system to provide a secure supply of electricity as per the technical criteria.

B9. **Avoidance of the Renewal/Replacement Costs of Infrastructure** defines the benefit a project can bring by avoiding or deferring the replacement or upgrading of existing infrastructure.

B10. **Redispatch Reserves** or **Reduction of Necessary Reserves for Redispatch Power Plants** describes a project's impact on the required levels of contracted redispatch reserve power plants by assessing the maximum power of redispatch with and without the project. A prerequisite for this indicator is the use of redispatch simulations.

[25] This category corresponds to Section 6: Methodology for RES Integration Benefit (B3).

[26] This category contributes to Section 8: Methodology for Variation in Grid Losses Benefit (B5)

The **costs** indicators are described as follows:

C1. **Capital expenditure (CAPEX)**. This indicator reports the capital expenditure of a project, which includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, ground, preparatory work, designing, dismantling, equipment purchases and installation. CAPEX is established by analogous estimation (based on information from prior projects that are similar to the current project) and by parametric estimation (based on public information about the cost of similar projects). CAPEX is expressed in euros.

C2. **Operating expenditure (OPEX)**. OPEX defines the annual operating and maintenance expenses associated with the project or investment. OPEX is expressed in euros per year.

Residual impact indicators refer to the impacts that remain after impact mitigation measures have been taken. Hence, impacts that are mitigated by additional measures should no longer be listed in this category. The indicators are defined as follows:

S1. **Residual Environmental impact** characterises the (residual) project impact on the environment, as assessed through preliminary studies, and aims to provide a measure of the environmental sensitivity associated with the project.

S2. **Residual Social impact** characterises the (residual) project impact on the (local) population affected by the project, as assessed through preliminary studies, and aims to provide a measure of the social sensitivity associated with the project.

S3. **Other impacts** provide an indicator of all other impacts of a project.

Although ENTSO-E intends to monetise as many of the indicators as possible, in some cases the required data is not always available (e.g., detailed emission prices per fuel type for non-CO_2 calculations). ENTSO-E seeks to deliver a uniform and objective CBA assessment and is reluctant to publish results if their uniformity and/or objectivity cannot be guaranteed. In such cases it is more useful to publish indicator results in their original units than to unilaterally decide on their monetary value in an arbitrary manner.

It should be noted that for those indicators that are required to be monetised, the euro values are to be represented as real and constant values. This means that no inflation is taken into account and, therefore, no forecasts for future inflation are necessary. It also means that values are taken as being fixed throughout the assessment by assuming constant year-of-study values. The year-of-study is taken as the year of the TYNDP, i.e., 2020 for the TYNDP 2020. The impact of taxation is not considered in the project assessments, so the values are to be represented as pre-tax values.

Table x provides an overview of the status, with regard to monetisation, of the benefit indicators included in this 3rd CBA guideline:

Table 1: Overview of the status of indicator monetisation

Indicator	Unit	Monetisation status		Document location
B1. SEW	€/yr	Monetised by definition		Section 4: Methodology for Socio-Economic Welfare Benefit (B1)
B2. CO_2 emissions	Tons/yr and €/yr	Comprises two parts: (1) Fully monetised in B1, where the effects of CO_2 emissions are monetised and reported as additional information under indicator B1. (2) Related to the additional societal value, which is not monetised under B1.	Political CO_2 reduction targets are formulated as percentages of values, expressed in tons per year. The monetary effect is the topic of ongoing political debate. Therefore, the CBA guideline requires that CO_2 emissions are reported separately (in tons).	Section 5: Methodology for Additional Societal benefit due to CO2 variation (B2)
B3. RES integration	MW or MWh/yr	Fully monetised under B1, where the effects of RES integration on SEW, due to the reduction of curtailment and lower short-run variable generation costs, are monetised and reported as additional information.	Political RES integration goals are formulated and expressed in MW. The monetary effect (in addition to B1, B2) cannot be monetised objectively. Therefore, the CBA guideline requires that RES integration is reported separately (MW or MWh/yr).	Section 6: Methodology for RES Integration Benefit (B3)
B4. Non-CO_2 emissions	Tons/yr	Not monetised		Section 7: Methodology for Non-Direct Greenhouse Emissions Benefit (B4)
B5. Grid losses	MWh/yr	Monetised using hourly marginal costs from the market simulations per price zone.		Section 8: Methodology for Variation in Grid Losses Benefit (B5)
B6. SoS: Adequacy	MWh/yr	Monetised. Is dependent on availability of VOLL-values. Additional adequacy margin may be conservatively monetised using investment costs in peaking units (provided figures are available).		Section 9: Methodology for Security of Supply: Adequacy to Meet Demand Benefit (B6)
B7. SoS: Flexibility (balancing energy exchange)	Ordinal scale	Not monetised.	Not monetised at present because of the unavailability of quantitative models. First development is to provide quantitative model results.	Section 10: Methodology for Security of Supply: System Flexibility Benefit (B7)

B8. SoS: Stability	Ordinal scale	Not monetised.	Not monetised at present because of the unavailability of quantitative models. First development is to provide quantitative model results.	Section 11: Methodology for Security of Supply: System Stability Benefit (B8)
B9. Avoidance of the Renewal/Replacement Costs of Infrastructure	€	Information delivered by project promoter		Section 12: Methodology for Avoidance of the Renewal/Replacement Costs of Infrastructure (B9)
B10. Redispatch Reserves	€/yr	Monetised using actual costs for allocation of redispatch reserves	This indicator is optional and can only be achieved when the SEW has been calculated using redispatch simulations	6.13 Reduction of Necessary

As the CBA guideline is a general guide for the assessment of projects, it would not be practical if detailed methodologies, parameters, or specific assumptions for the calculation of each indicator were included in this document. Therefore, the CBA guideline needs to be complemented by additional detailed information on how the simulations are to be performed. This additional information needs to be published within the respective studies and shall specify which method is to be used in case the CBA guideline allows more than one possibility, as well as how to interpret the rules defined in the CBA guideline.

For the CBA phase of the TYNDP process, implementation guidelines will be prepared that contain all of the necessary details required to calculate the indicators, taking into account the modelling possibilities and assumptions that can be applied in the relevant TYNDP. Together with the Scenario Report (where all scenario specific details that are not defined in the 3rd CBA guideline are given) and the Implementation Guideline, the CBA guideline provides an exhaustive guidance on how to perform the project specific assessment within the TYNDP process.

Table 2 contains a summary of details for certain indicators that are to be defined in complementary documents, which focus on the TYNDP process. If applied to other studies, these details must also be given within the respective study.

Table 2: Summary of indicators for which complementary documents are to be defined.

Indicator or rule	To be defined in:	Information required to be provided
Simulation tools used to perform the assessment	To be defined within the documentation of the TYNDP	List of tools used for Market, Network, and Redispatch simulations.
Transfer capability calculation	Implementation Guidelines	Power shift method to be applied (generation shift and/or load shift; how to scale the generation units or loads in the system when applying the power shift). Selection of contingencies and critical branches. Details of internal GTC calculation.
Impacts of third-countries	Implementation Guidelines	Method to remove the effects of non-European countries from the pan-European results.
Baseline/reference network	Specific document on the reference grid	Definition of the reference grid together with a justification for the chosen reference grid/s.
Market simulations	Implementation Guidelines	Value of hurdle cost to be used. Number of climate years to be used.
Network simulations	Implementation Guidelines	Mapping the market results to the network model (nodal level) Load-flow method to be applied with explanation (whether AC or DC)
B1. Socio-economic Welfare	Implementation Guidelines	Method on reporting the part of SEW from fuel savings due to integration of RES (SEW-RES) and the avoided CO_2 cost (SEW-CO_2). Detailed description of generation cost approach and total surplus approach. In case of redispatch simulations, a detailed description of the methodology used must be given.
B2. CO_2 Emissions	Implementation Guidelines	Societal cost to be used.
B3. RES Integration	Implementation Guidelines	How to report avoided RES spillage (dump energy) from the market simulation results.
B4. Non-direct greenhouse Emission	Implementation Guidelines	List of emission types and factors per generation category.
B5. Variation in Grid Losses	Implementation Guidelines	Monetisation of losses on HVDCs between different market nodes. Assumption to apply for compensation of partial double counting with SEW. Number of climate years to be used. Information regarding whether points in time were used and the specific points in time used.
B6. Security of Supply: Adequacy to Meet Demand	Implementation Guidelines	Method for introducing peaking units in TOOT cases. Definition of which sanity check method is to be used. Details of Monte-Carlo approach. Value of CONE.
B8.2. Blackstart services	Given by the project promoters or in Implementation Guidelines	Definition of the necessary assumptions (e.g., blackout probability, blackout duration, costs for blackout, etc.).
Project Costs	Implementation Guidelines	Definition of the costs delivered within the project sheets.
VOLL	Implementation Guidelines	The values used will be defined in the implementation guideline according the most recent agreed

		values.
Investment value calculation	Implementation Guideline	The assessment period and real discount rate could be confirmed or updated with respect to what it is indicated in the 3rd CBA Guideline

6.4 Section 4: Methodology for Socio-Economic Welfare Benefit (B1)

Indicator definition:

- Definition: In power system analysis, socio-economic welfare is typically defined as the sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners (congestion rent).
- Relevance: This indicator gives a direct measure for the monetary benefit and is therefore of great relevance for the CBA.

Indicator calculation:

- Model: Market simulations, Redispatch simulations; based on a system cost comparison with/without the project.
- Quantitative measure: this indicator is directly given in monetary values.
- Monetisation: per definition monetized and given in €/year

Interlinkage to other CBA indicators:

- B2, B3, B6

Introduction

In power system analysis, socio-economic welfare is typically defined as the sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners (congestion rent). Transmission network projects, or investments, have an effect on the sum and the distribution of these surpluses. Investment in transmission capacity generally increases the total sum of the individual surpluses by enabling a larger proportion of demand to be met by cheaper generation units that were not available before because of a transmission bottleneck.

These surplus effects are only one part of the overall economic benefit provided by transmission investments that stem from wholesale energy market integration and do not capture other transmission-related benefits as described by the other indicators, as given in this guideline.

Calculations within the respective studies (e.g., the TYNDP) should be based on a set of scenarios, which are designed to represent future conditions with regard to generation and demand. The contents of the scenarios are carefully determined and take into account a coherent set of assumptions with regard to possible developments in generation and load. This allows the marginal benefits of a transmission project to be assessed against a 'static' reference framework. In reality, the transmission project actually alters the reference framework itself – albeit with a (often significant) time delay. Considering that these longer-term effects make the modelling challenge considerably more complex and decrease the robustness of results, the strength of an approach based on reporting the marginal differences in short-run surplus lies in its unambiguity.

Methodology

The TYNDP reports changes to economic surpluses as a result of transmission projects, i.e., 'deltas' between situations with and without the project under consideration. It unambiguously reports the marginal change to the total economic surplus in the event of building a transmission project, without the need to further consider secondary consequences, which are usually not merely the result of constructing the transmission project but rather the result of (related and unrelated) further (political) decisions.

In order to calculate the change in short-term economic surplus, a perfect market is assumed. The perfect market assumes all market participants have equal access to information, no barriers to entry or exit, and no market power.

In general, two different approaches can be used for calculating the variation in socio-economic welfare:

- The generation cost approach, which compares the generation costs with and without the project for the different bidding areas; and

- The total surplus approach, which compares the producer and consumer surpluses for both bidding areas, as well as the congestion rent between them, with and without the project.27

When measuring the benefits of transmission investments under the assumption of perfectly inelastic demand, the change in socio-economic welfare is equal to the reduction in total variable generation costs. Hence, if demand is considered as perfectly inelastic to price, both methods will yield the same result. This metric values transmission investment in terms of saving total generation costs, as a project that increases the commercial exchange capability between two bidding areas allows generators in the lower priced area to export power to the higher priced area, as shown in Figure 9.

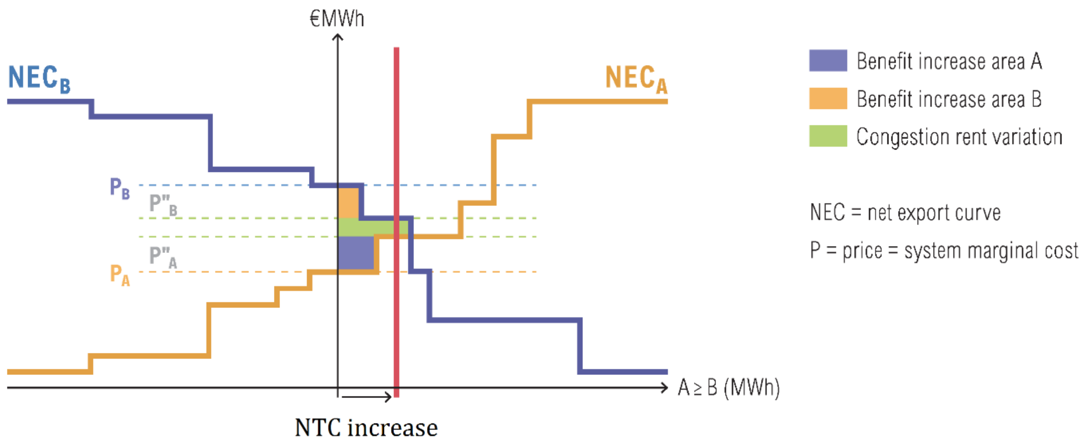


Figure 9: Illustration of benefits due to NTC increase between two bidding areas -+

[27] More details about how to calculate surplus are provided in Section 4: Methodology for Socio-Economic Welfare Benefit (B1)

The new transmission capacity reduces the fuel and other variable operating costs and, hence, increases total socio-economic welfare. Total generation costs are equal to the sum of thermal generation costs (fuel plus CO_2 ETS costs), and DSR costs. The different cost terms generally used in market simulations are shown in the Table 3: cost terms used in market simulations.

Table 3: cost terms used in market simulations

Cost terms in market simulations	Description
Fuel costs	Costs for fuel of thermal power plants (e.g., lignite, hard coal, natural gas, etc.).
CO_2-Costs	Costs for CO_2-emissions caused by thermal fired power plants. Depends on the power generation of thermal power plants and price of CO_2.
Start-up-costs/Shut-down costs	These terms reflect the quasi-fixed costs for starting up a thermal power plant to at least a minimum power level.
Operation and maintenance costs	Costs for operation and maintenance of power plants.
Demand Side Response (DSR) costs	Costs of DSR. DSR is the load demand that can be actively changed by a certain trigger.

If demand is considered elastic, modelling becomes more complex. Most European countries are considered to have price inelastic demand. However, there are a number of developments that appear to increase the price elasticity of demand. These developments include smart grids and smart metering, as well as a growing need for flexibility in order to accommodate the changing production technologies (i.e., more renewables, less thermal and nuclear).

The choice of assumptions regarding demand elasticity and the methodology for the calculation of socio-economic welfare benefit is left to ENTSO-E's Regional Group to decide. There are two recognised approaches to taking into account greater flexibility of demand when assessing socio-economic welfare, and these are listed below. The choice of the approach needs to be decided within the respective study, e.g., based on the respective Implementation Guidelines.

In the first approach, demand is estimated through scenarios, which results in a reshaping of the demand curve (in comparison with present curves) to model the future introduction of smart grids, electric vehicles, etc. In this case, demand response is not elastic at each time step, but constitutes a shift of energy consumption from time steps with potentially high prices to time steps with potentially low prices (e.g., on the basis of hourly RES availability factors). The generation costs to supply a known demand are minimised through the generation cost approach. This assumption simplifies the complexity of the model and, therefore, the demand can be treated as a time series of loads that have to be met, while at the same time considering different scenarios of demand-side management.

The second approach introduce hypotheses regarding the level of price elasticity of demand. To do this, there are two possible methods:

- Generation cost method:

Using the generation cost approach, price elasticity could be taken into account via the modelling of curtailment as generators. The willingness to pay would then, for instance, be established at very high levels for domestic consumers and at lower levels for a part of industrial demand.

- Total surplus method:

  Using the total surplus method, the modelling of demand flexibility would need to be based on a quantification of the link between price and demand for each hour, allowing a correct representation of demand response in each area.

These methods are discussed in detail in the Annexes. Annex I addresses the generation cost method and Annex II addresses the total surplus method.

Changes in SEW must be reported in euros per year (€/yr) for each project, for a given scenario and study year. In addition to the overall socio-economic welfare changes, the SEW changes that are the result of integrating RES and/or variations in CO_2-emissions must be reported separately as follows:

- Fuel savings due to integration of RES; and
- Avoided CO_2 emission costs.

Monetisation

This indicator is measured in €/yr and is, therefore, monetised by default.

The effects of CO_2 emissions, based on assumptions regarding emission costs, are monetised and reported as additional information under indicator B1.

The effects of RES integration on SEW due to the reduction of curtailment and lower short-run variable generation costs is monetised and reported as additional information under indicator B1.

Independent of the methodology used to calculate the SEW, the result will be given as a single value in €/yr as received by the respective methodology (i.e., no summation of the values achieved by the different methods) plus additional information on the RES and CO_2 impact on the SEW.

For cross-border projects, either the reduced generation costs/additional overall welfare or the combination with redispatch costs are calculated. For projects that have no cross-border capacity impact, only the redispatch methodology is used. At the end, only one value for the indicator is given. The method used to calculate the SEW must always be reported.

An overview of the different methods to calculate the SEW is given in Table 4: Reporting Sheet for this Indicator in the TYNDP.

Table 4: Reporting Sheet for this Indicator in the TYNDP.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
SEW: Reduced generation costs/ additional overall welfare	Market studies (optimisation of generation portfolios across boundaries)	€/yr	per definition monetary	European
SEW: Redispatch costs	Redispatch studies (optimisation of generation dispatch within a boundary considering grid constraints)	€/yr	per definition monetary	Regional/Project promoter (PP) level
SEW: Reduced generation cost/ additional overall welfare + Redispatch costs	Combination of both market- and redispatch-simulation	€/yr	per definition monetary	Regional/PP level

6.5 Section 5: Methodology for Additional Societal benefit due to CO_2 variation (B2)

Indicator definition:

- Definition: This indicator gives the change in CO_2 emission due to a new project or investment and in divided into two parts: the pure CO_2 emission in tons and additionally the societal costs in €/year. Both measures have to be displayed.
- Relevance: The European electricity system is a significant contributor to CO_2 emissions. In this context, grid development can play a role in modifying the level of carbon emissions. Due to the common goal to limit global warming and its harmful impact on the world both measures of CO_2 (absolute and monetary) are given.

Indicator calculation:

- Model: Market simulations, Network simulations, Redispatch simulations; based on the CO_2 emissions comparison with/without the project.
- Quantitative measure: this indicator is for the first part given in tons
- Monetisation: the second part is monetized by multiplication of CO_2 emissions [t] and a defined factor [€/t]

Interlinkage to other CBA indicators:

- B1, B3, B5

Introduction

As a signatory of the Paris Agreement, the European Union is committed to lower its carbon impact. In November 2018, the European Commission presented its strategic long-term vision for a prosperous, modern, competitive, and climate-neutral Europe by 2050. This common goal aims to limit global warming and its harmful impact on the world. The European electricity system is a significant contributor to CO_2 emissions. In this context, grid development can play a role in modifying the level of carbon emissions. In particular, new interconnector projects enable cheaper generators to replacing more expensive plants with potentially higher CO_2 emissions, leading to potentially lower CO_2 emissions. Similarly, storage projects can have the same impact.

To fully display the benefits of reducing CO_2 emissions due to a new project or investment, this indicator is divided into two parts:

- Part 1 refers to the change in pure CO_2[28] emissions given in tons; and

[28] All CO_2 values (in [t] and ETS costs) are considered being pure CO_2 without taking into account equivalents as coming from other emission types.

- Part 2 refers to its monetisation. The monetary part of CO_2 is partly taken into consideration within SEW and losses through the generation cost. The marginal cost for each power plant is the sum of the fuel cost and the CO_2 market price. This CO_2 price, which is paid for by the producers, is the forecast of the CO_2 price over the Emission Trading Scheme (ETS). Depending on the level of this market price, the forecasted price signal may be too low to give a sufficient price signal to lead to the investment level required to reach Europe's climate goal.

Thus, in order to appropriately assess investments in accordance with the European objective of CO_2 emission reduction, a specific indicator for monetising this additional impact is designed. For this purpose, the variation in CO_2 emissions is valued at the appropriate level of a societal cost. This cost represents the effort that should be made in order to reach the European climate-neutral goal.

Methodology

The CO_2 emissions are computed with and without the project. The variations that are taken into account for this indicator are:

- Variations resulting from the change of generation plan; and
- Variations resulting from the change of losses volumes.

In order to not double account with the CO_2 variation already monetised into the SEW (B1) and the losses (B5), changes in CO_2 emission are then multiplied by the difference between the CO_2 societal cost and the ETS price used in the scenario. This benefit (B2) is to be added to the overall monetary benefit.

This is shown as follows:

$$\boldsymbol{B2 = CO_2 variation} * (\boldsymbol{Societal\ cost\ of\ CO_2 - ETS\ CO_2\ price})$$

Example: for a hypothetical project from A to B

The impact of the project is described as follows:

- Impact on CO_2 emissions on the generation plan (using market simulations): -0.8 Mton/yr; and
- Impact on CO_2 emission of losses volume changes: +0.2 Mton/yr

Given that the ETS price in the scenario is 27 €/ton; and

Societal cost is taken as 163 €/ton[29], the benefit is calculated as follows:

- B2 benefit = (0.8 – 0.2)*(163 – 27) = 81.6 M€/yr

[29] This is only an example.

Monetisation

The CO_2 cost used should be based on reputable scientific investigations and international studies. Because of the expected spread of values that typically arise from different sources, the cost that is used should ideally be agreed between the main stakeholders. The societal cost of carbon can represent two concepts:

- The social cost that represents the total net damage of an extra metric ton of CO_2 emission due to the associated climate change;[30] and
- 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.[31]

It is important to emphasise that this 'societal cost of CO_2' is a different concept to 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 has a direct effect on SEW; hence, it is fully captured by indicators B1 and B5 (and also reported as such alongside the B1 and B5 indicators). However, the cost of CO_2 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 CO_2 emissions is a political choice. Moreover, it is one that requires reliance on different, and potentially contradicting, reports on the actual long-term harmful effects of CO_2.

The reporting requirements are described in the reporting sheet in Table 5: Reporting Sheet for this Indicator in the TYNDP.

Table 5: Reporting Sheet *for* this Indicator in the TYNDP

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tons/yr	Per definition not monetary	European
CO_2 emission from losses variation	Network studies (losses computation)	Tons/yr	Per definition not monetary	European
Societal costs of CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	€/yr	Societal costs decreased by ETS costs as used in the scenario (to avoid double accounting with B1)	European
Societal costs of CO_2 emissions from losses variation	Network studies (losses computation)	€/yr	Societal costs decreased by ETS costs as used in the scenario (to avoid double accounting with B5)	European

[30] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2
[31] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2

6.6 Section 6: Methodology for RES Integration Benefit (B3)

Indicator definition:

- Definition: It measures the 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: As RES integration can be seen as the main driver for reducing the CO_2 output it will be given as stand-alone indicator

Indicator calculation:

- Model: Market simulations, Redispatch simulations; based on the RES integrated in the system as comparison with/without the project; or: direct measure when directly connecting RES sources.
- Quantitative measure: this indicator is given in MWh/year for reduced RES spillage or in MW for direct connected RES sources.
- Monetisation: this indicator will not be monetised

Interlinkage to other CBA indicators:

- B1, B2

Introduction

The RES Integration Benefit indicator provides a stand-alone value for the additional RES available for the system as a result of the reinforcement project or investment. It measures the reduction of renewable generation curtailment in MWh (avoided spillage) and the additional amount of RES generation that is connected by the project.

The volume of integrated RES (in MW or MWh) must be reported in any case. 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.

Methodology

An explicit distinction is made between RES integration projects related to either:

- The direct connection of RES to the main system; or

- Projects that increase the capacity in the main system itself.

Although both types of projects can lead to the same indicator scores, they are calculated on the basis of different measurement units.

Direct connection is expressed in $MW_{RES\text{-}connected}$ (without regard for actual avoided spillage).

The capacity-based indicator is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system.[32]

Avoided spillage is extracted from the studies for indicator B1. Connected RES is only applied for the direct connection of RES integration projects. 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.

Monetisation

Increasing the penetration of RES in the electricity system has an impact that is fully captured by other indicators (i.e., B1, with regard to changes in the variable cost of electricity supply; and B2, a reduction of CO_2 emissions).

The reporting requirements are described in the reporting sheet in Table 6.

Table 6: Reporting Sheet for this Indicator in the TYNDP

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence of Monetary Measure
Connected RES	Project specification	MW	Per definition not monetary	European
Avoided RES spillage	Market, , or redispatch studies	MWh/yr	Included in generation cost savings (B1) and variation in CO_2 emissions (B2)	European

Double-counting

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 (i.e., B1 and B2, respectively).

[32] Calculating the impact of RES in absolute figures (MW) facilitates the comparison of projects throughout Europe when considering the sole aspect of RES integration. Relative numbers (i.e., the contribution of a project compared to the objectives of the NREA) can easily be calculated ex-post for analysis at a national level.

6.7 Section 7: Methodology for Non-Direct Greenhouse Emissions Benefit (B4)

Indicator definition:

- Definition: This indicator gives the change in non-direct greenhouse emissions due to a new project or investment.
- Relevance: In addition to the B2 indicator, other non-CO2 emissions must be considered as they also have an impact on climate change so cannot be neglected. Pollution levels are increased via direct emissions, such as particulate matter and toxic elements, or via indirect methods that promote chemical reactions.

Indicator calculation:

- Model: Market simulations, Redispatch simulations; based on the non-CO_2 emissions comparison with/without the project.
- Quantitative measure: this indicator is given in tons/year
- Monetisation: this indicator will not be monetised

Interlinkage to other CBA indicators:

- none

Introduction

Following the Paris Climate Agreement, the goal of reducing the greenhouse gases is focussed on keeping the global temperature increase below two degrees Celsius, relative to pre-industrial levels. The main focus in achieving this goal is the reduction in CO_2 emissions, which is described as a benefit indicator in Section 5: Methodology for Additional Societal benefit due to CO2 variation (B2).

In addition, other non-CO_2 emissions must be considered as they also have an impact on climate change so cannot be neglected. Pollution levels are increased via direct emissions, such as particulate matter and toxic elements, or via indirect methods that promote chemical reactions (e.g., cause acid rain). In order to properly take into account the mitigation effects of transmission and storage projects, specific efforts should also be taken for these non-CO_2 emissions. This should at least include the main emission types of CO, NO_2 (including NO that reacts to form NO_2 within the atmosphere), SO_2, and particulates ($PM_{2.}$ PM_5, and PM_{10}).

Methodology

The quantity of each emission type can be calculated as a post process based on the year-round power plant dispatch that is produced by the market (redispatch) simulations. This is achieved by multiplying a specific emission factor in [t/MWh] by the yearly generation in [MWh] of a single power plant. This in principle has to be done for each power plant and each emission type, as the emission mechanism is specific for each single thermal power plant. As this is a very complex topic, for sake of simplicity, the emission model can be applied per technology type. It should be noted that, in general, these emission types can differ for different countries depending on the installed composition of power plants: e.g., more modern power plants will have a higher efficiency and, therefore, a lower emission factor, but old power plants can also install new technologies to reduce non-CO_2 emissions (e.g., low NO_x burners). This needs to be taken into account when defining the fuel type specific emission factors. If this is not possible because of the lack of sufficient data availability, the reduction to one factor per emission type can also be accepted.

The non-CO_2 indicator/s can be calculated per fuel type by multiplying the specific emission factor (for all emission types) in [t/MWh] by the respective generation in [MWh]. The indicator will be given in tons per year [t/yr].

Monetisation

A monetisation of the non-CO_2 indicator is currently not proposed in this methodology. This is because it is unlikely that future improvements in emission reductions, because of filters or increases in efficiency, will have a comparable effect at lower costs. When monetising the non-CO_2 indicator, a project might become beneficial, or even non-beneficial, simply because of this impact, which is most likely not the main aim of building the project. Therefore, it can be strongly impacted by future technologies. However, at the moment no such future technologies are in place, the non-CO_2 indicator has to be shown on a quantified basis in order to complement the CBA assessment.

The reporting requirements are described in the reporting sheet in Table 7.

Table 7: Reporting Sheet for this Indicator in the TYNDP. Each single emission type has to be given separately

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
Non-CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tons/yr	Per definition not monetary	European

6.8 Section 8: Methodology for Variation in Grid Losses Benefit (B5)

Indicator definition:

- Definition: The Variation in Grid Losses Benefit indicator is used to reflect the changes in transmission system losses that can be attributed to a project or investment.
- Relevance: The energy efficiency benefit of a project is measured through the change of thermal losses in the grid. At constant power-flow levels, network development generally decreases losses, thus increasing energy efficiency. Specific projects may also lead to a better load-flow pattern when they decrease the distance between production and consumption. Increasing the voltage level and the use of more efficient conductors also reduce losses.

Indicator calculation:

- Model: Network studies; based on the losses comparison with/without the project.
- Quantitative measure: losses are given in MWh/year
- Monetisation: amount of losses multiplied by marginal costs

Interlinkage to other CBA indicators:

- B1, B2

Introduction

The Variation in Grid Losses Benefit indicator is used to reflect the changes in transmission system losses that can be attributed to a project or investment.

The energy efficiency benefit of a project is measured through the change of thermal losses in the grid. At constant power-flow levels, network development generally decreases losses, thus increasing energy efficiency. Specific projects may also lead to a better load-flow pattern when they decrease the distance between production and consumption. Increasing the voltage level and the use of more efficient conductors also reduce losses.

It should be noted that currently the main driver for transmission projects is the need for transmission over long distances, which may increase losses. Although new interconnections generally decrease the electrical resistance of the grid and consequently the losses, the additional exchanges, resulting from the increase of the transfer capacities, and the change in generation size can lead to the increase. The precise location of generation units also has a significant effect on the amount of losses, as generation at different nodes leads to different flows.

Methodology

The difference in losses (in units of energy [GWh][33]) and its monetisation is calculated for each project by calculating the grid losses in two different simulations, with the help of network studies, i.e., one simulation with the project and one simulation without the project.

- **Relevant geographical area/grid model**

  The calculated losses should be representative of Europe as a whole. However, they may be approximated by a regional losses modelling approach for the time being. Thus, the minimum requirement should be to use **regional network model(s)**. These regional models should include at least the relevant countries/bidding areas for the assessed project, typically the hosting countries, their neighbours, and the countries on which the project has a significant impact in terms of cross-border capacity or generation pattern (as given by the market simulation). Practically, the model for the whole synchronous area in which the project is located should be used. In the case of HVDC projects that connect different synchronous areas, the losses need to be calculated in both synchronous areas (unless the HVDC project is connected to a third country).

  By default, losses should be calculated using AC load-flow. If AC load-flow cannot be implemented in a reliable way (taking into account modelling assumptions, available input data, and calculation times), then DC load-flow can be used to approximate the active power-flows.

  When DC load-flow is used, the results of the calculations are the active power-flows on the AC lines and transformers. As the grid model contains the resistance values for all branches, the losses on each branch can be estimated using the following formula:

$$Losses\ [MW] = R\frac{P^2}{U^2\cos^2\varphi}$$

  Where:

  P is the active power-flow from the DC calculation;

  R is the resistance of the branch;

  U is the voltage level; and

  Cosφ is an assumed power factor used to estimate the effect of reactive flows. For this, a common value (e.g., 0.95) is to be used for all calculations within a study.

  The result of the losses calculation should provide an amount of losses **at least at a market node level** for the countries included in the model in order to be able to monetise them.

- **Relevant period of time**

[33] Due to possible magnitude, an appropriate representation should be used e.g., GWh

A calculation over the complete year, with sufficiently small time steps (typically one hour), should aim to be the closest to reality. The chosen methodology must be representative for the considered period of time, which must be verified within the study (e.g., in the current TYNDP scenarios, this means one complete calendar year).[34]

- **Market results/generation pattern with and without the project or in grid-stressed situations**

  As a TYNDP project will likely have an impact on internal or cross-border congestions, the generation pattern can differ significantly with and without the project, thus having an impact on losses. The change in generation can be considered through:

  - A change in the NTC used for the market simulation, and/or
  - For internal projects/generation accommodation projects, a re-dispatch methodology could be used.

  In any case, the new generation pattern should not cause congestions elsewhere in the grid.

Monetisation of losses

When the losses (i.e., in MWh) are calculated, they can be monetised. It is important, when calculating the monetised values that this is done in a consistent manner for all assessed projects. In a general sense, this should be assessed with the perspective of the cost that is borne by society to cover losses.

The approach is based on market prices that are taken from the marginal cost, as given by the market simulation. More precisely, for a given project, losses are calculated for each time step of the year, *h*, and each market zone, *i*:

- The amount of losses, $p'_{h,i}$ (with project) and $p_{h,i}$ (without project) in MWh after eventual measures for securing the grid situation; and
- The marginal costs, $s'_{h,i}$ (with project) and $s_{h,i}$ (without project) in €/MWh for a given time step.

The delta cost of losses should be calculated as the sum of *h* and *i* of the term $(p'_{h,i} * s'_{h,i}) - (p_{h,i} * s_{h,i})$. In this case, eventual re-dispatch costs are not taken into account.

The prerequisites for the calculation are the computation of the marginal cost and amount of losses for each market zone, with and without the assessed project.

The formula for losses monetisation is as follows:

$$Yearly\ cost\ C = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} s_{h,i} \cdot p_{h,i} \right)$$

[34] As a provisional exception, a computation of losses based on definite points in time can be used to approximate year-round losses. In such case, the chosen points in time should be numerous enough to ensure representativeness and weighted in a correct manner.

The yearly cost has to be calculated for the base case and the TOOT or PINT case (depending on the type of the project), using two market outputs. The final monetised result (i.e., delta cost) is the difference between the two cases.

The market simulations may contain extremely high marginal costs in certain hours for modelling reasons, such as in the case of loss-of-load (ENS). As a result, the marginal price during these hours does not represent the societal cost and, if used for monetisation, can distort the results. Therefore, for each market node, the market price used for the losses monetisation should be capped to the most expensive generation category of the scenario.

It is important to note that the losses calculated with the project do include the losses on the project elements themselves.

The reporting requirements are described in the reporting sheet in Table 8.

Table 8: Reporting Sheet for this Indicator in the TYNDP

Parameter	Source of Calculation[35]	Basic Unit of Measure	Monetary Measure	Level of Coherence of Monetary Measure
Losses	Network studies	MWh/yr	€/year (market-based)	European

Double-counting

For the market simulations, demand curves are built to contain grid losses (i.e., using historical time series), which means that parts of the losses are already monetised under the B1 indicator SEW (namely, in the consumer surplus, which takes into account the effect of the change in marginal costs, brought about by the project, on the losses part of the demand).

This effect needs to be taken into account when monetising the losses from the network simulations.

There are two possible assumptions that can be made to deal with this issue:

- **Compensation assuming a given proportion of the demand as losses:**

  In this case, the compensation of the results with assumptions for the losses included in the demand in each market node is needed. As the typical grid losses may significantly vary among countries, it is recommended to not use a uniform European value. The following compensation term must be computed for both reference and TOOT/PINT cases, and then subtracted from the monetised losses:

$$Compensation = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} Ks_{h,i} d_{h,i} \right),$$

[35] Cf Annex IV, 2c.

Where:

K is the portion of the demand assumed to be losses, and

$d_{h,i}$ is the demand on the market node, *I*, in hour, *h*.

With this compensation, the monetised delta losses are:

$$Delta\ Losses\ (monetized) = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} s'_{h,i} p'_{h,i} - s_{h,i} p_{h,i} - K d_{h,i} (s'_{h,i} - s_{h,i}) \right)$$

Generally, the K factor might come from the TSOs, or assumed centrally for each country, based on historical values.

- **Compensation with the computed losses:**

Assuming that the losses computed in the case without the project are included in the demand, the formula to monetise the delta losses simplifies to the following:

In the case of PINT projects:

$$Delta\ Losses\ (monetized) = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} s'_{h,i} (p'_{h,i} - p_{h,i}) \right)$$

In the case of TOOT projects:

$$Delta\ Losses\ (monetized) = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} s_{h,i} (p'_{h,i} - p_{h,i}) \right)$$

The advantage of this method is that no data collection from the TSOs, or any further assumptions, are needed, but the computed losses might differ from the unknown losses that are included in the demand.

An example is provided below that demonstrates how the simplified formulas can be obtained.

Example: Illustration of the two assumptions used to deal with double counting using one hour and one market area.

A simple example is presented below for only one hour and one market area, in order to demonstrate the double-counting problem and the two different assumptions for the compensation.

Starting from the original formula (for one hour):

- Delta monetised losses $= \boldsymbol{p' \cdot s' - p \cdot s}$

Now assume:

- A: being the general losses (e.g., 2% of actual load)
  - A
- B: is the difference between A and the calculated losses in the reference case
  - $\mathrm{B = p - A}$ for PINT projects and $\mathrm{B = p' - A}$ for TOOT projects
- C: is the difference between the losses with and without the project
  - $\mathrm{C = p' - p}$

Let us write *p* and *p'* using A, B, and C (Although A and B are **not known, C can be derived from grid simulations**):

In the reference case, the losses are always equal to $\boldsymbol{A + B}$ (*p* in the case of PINT projects and *p'* in the case of TOOT projects).

Then, the PINT and TOOT cases need to be handled separately.

In the case of PINT projects:

$$\boldsymbol{p} = A + (p - A) = \boldsymbol{A + B}$$

$$\boldsymbol{p'} = A + (p - A) + (p' - p) = \boldsymbol{A + B + C}$$

In the case of TOOT projects:

$$\boldsymbol{p'} = A + (p' - A) = \boldsymbol{A + B}$$

$$\boldsymbol{p} = A + (p' - A) - (p' - p) = \boldsymbol{A + B - C}$$

The delta monetised losses will become:

$$\boldsymbol{p' \cdot s' - p \cdot s}$$

$$(A + B + C) \cdot s' - (A + B) \cdot s \text{ for PINT projects;}$$

$$(A + B) \cdot s' - (A + B - C) \cdot s \text{ for TOOT projects.}$$

Simple equation transformation leads to:

$$A \cdot (s' - s) + B \cdot (s' - s) + C \cdot s' \text{ for PINT projects;}$$

$$A \cdot (s' - s) + B \cdot (s' - s) + C \cdot s \text{ for TOOT projects.}$$

Only the first term is already included in the SEW (delta in consumer surplus), therefore, only this part is double accounted and needs to be subtracted.

But as A is not known, one of the two assumptions needs to be made:

- Assume an estimate of A:

  After having calculated the change in losses as: $\boldsymbol{p}' \cdot \boldsymbol{s}' - \boldsymbol{p} \cdot \boldsymbol{s}$, a correction needs to be applied. Assuming that A is 2% of the load, then the correction (to be subtracted from the final result) will become:

  $$0.02 \cdot load \cdot (s' - s)$$

- Assume that the calculated losses are equal to the assumed losses. In this case, B will equal 0, and the monetised change in losses is given by:

  $$A \cdot (s' - s) + B \cdot (s' - s) + C \cdot s' \text{or } A \cdot (s' - s) + B \cdot (s' - s) + C \cdot s$$

  This will be reduced to $C \cdot s'$ for PINT projects and $C \cdot s$ for TOOT projects because B is 0 and the first term is already included in SEW.

6.9 Section 9: Methodology for Security of Supply: Adequacy to Meet Demand Benefit (B6)

Indicator definition:

- Definition: Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity to meet the demand at any moment in time.
- Relevance: A new interconnector may help adequacy by pooling the risk of loss-of-load while at the same time pooling the means (generation capacity) to deal with it. The interconnector can mitigate the adequacy risks among European countries and, in particular, the two linked by the interconnector.

Indicator calculation:

- Model: Monte Carlo based Market simulations; based on the EENS comparison with/without the project.
- Quantitative measure: EENS avoided is given in MWh/year
- Monetisation: multiplying the EENS reduction by the Value of Lost Load (VOLL)

Interlinkage to other CBA indicators:

- none

Introduction

Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity to meet the demand at any moment in time, i.e., a sufficient volume of power is available and can be physically delivered to consumers at any time, including under extreme conditions (e.g., cold wave, low wind generation, unit or grid outages, etc.).

To achieve this, generation and transmission capacity are complementary elements: i.e., generation capacity requires a transmission grid for power to flow from the generation source to the load. This is particularly relevant in the context of geo-temporal fluctuations in intermittent renewable energy sources, which may require certain areas to depend on generation that is only available in other areas at a certain moment. Transmission capacity makes it possible to meet demand in one area with generation capacity that is located in another area.

A new interconnector may help adequacy by pooling the risk of loss-of-load while at the same time pooling the means (generation capacity) to deal with it. The interconnector can mitigate the adequacy risks among European countries and, in particular, the two linked by the interconnector. The less likely it is that the stressed events of the countries occur simultaneously, the higher the adequacy benefit of a new interconnector. Non-simultaneous stressed events mean that when one country is facing adequacy risks, the other could provide power.

Practically, the benefit can be seen in two ways:

- A decrease in the need for generation capacity: For an equivalent SoS level, in terms of LOLE[36] and EENS, an interconnector can decrease the peaking unit capacity needs.

- A decrease in EENS volumes: When only one country is facing a loss of load, a new interconnector can help to import more, thereby reducing EENS.

More generally, the benefit could be a combination of the two effects (with the combination evolving with time).

The adequacy benefit of a project or investment can be assessed using two approaches. One approach uses the decrease in peaking unit investment needs (for the same SoS level). Another approach uses the reduction of EENS volume (installed capacity remaining constant). Some implementation difficulties favour the use of an EENS based methodology. However, a sanity check based on investment saving is proposed to make the assessment more robust. This allows a link to be made with benefit that might be present for some countries that have capacity remuneration mechanisms in place for adequacy purposes.

Loss of load is a rare phenomenon, resulting from the combination of extreme events. Studying loss of load, therefore, requires a refined model of the hazards that could affect the power system. This refined model is essential to depict loss of load characteristics, such as its deepness and simultaneity with other countries. **Several hundreds of Monte Carlo years (MCY) are consequently necessary** using the several climate year datasets combined with plant (and if possible grid) outage patterns.

In addition, studying adequacy requires generation portfolios to be adequate. This means that LOLE should be realistic and reasonable.[37] The scenario used to compute the SoS adequacy benefit must abide by this principle. It is advisable to ensure that such a setup is met without the studied project to avoid unrealistically high LOLE when removing the project. TYNDP scenarios are adequate under the reference grid, so for TOOT projects, a small adaptation could be necessary if the countries are no longer adequate when the project is removed. The adaptation would only consider adding a few peaking units.

Methodology

The methodology involves a number of steps that are described as follows:

- **Step 1**

  If necessary, the scenario should be adapted to ensure realistic LOLE levels without the project. The LOLE is considered realistic if it is in a range of 1 hour lower or higher than the LOLE legal standard.

[36] Loss of load expectation represents the expected number of hours over a year when loss would occur (for each country it results from a comparison of load with available generation and possible exchange with neighboring countries).
[37] Using national adequacy standard, for instance; if such standards don't exist, use 3h/yr.

This step is only needed for TOOT projects, as the scenarios should be already adapted for the reference grid. Thus, it might be necessary to add peaking power plants in certain countries to adhere to the adequacy standard without the project. If an adjustment must be made, its extent should be clearly reported.

This step is necessary because for some TOOT projects, removing the interconnector would lead to an unrealistically high LOLE and, consequently, unrealistically large values. This situation would not have occurred if the interconnector had not been commissioned, because the generation fleet would have increased to avoid such LOLE. Note that for the assessment, ENTSO-E generally makes the (simplified) assumption that generation is not dependent on the interconnector levels. This assumption cannot hold in the case of adequacy, which is directly impacted by both generation capacities and interconnector levels. Therefore, the slight adaptation may be needed for TOOT projects, making the assessment slightly conservative.

- **Step 2: EENS saved**

  Perform two Monte Carlo simulations with and without the project, and assess the EENS reduction. Monetise the benefit by multiplying the EENS reduction by the Value of Lost Load (VOLL).

- **Step 3: Sanity check**

  A sanity check is performed to cap the value computed by EENS savings. This cap represents the value of the generation capacity that would have been necessary to reach an equivalent level of adequacy (compared with the addition of the project). Note that for an X MW interconnector, 2*X MW of peaking unit capacity is an immediate cap. The details on how to perform the sanity check needs to be given in the respective study (e.g. the Implementation Guidelines for TYNDP).

Monetisation

This indicator is measured in €/yr, so it is monetised by default.

The reporting requirements are described in the reporting sheet in Table 9.

Table 9: Reporting Sheet for this Indicator in the TYNDP

Parameter	Source of calculation[38]	Basic unit of measure	Monetary measure	Level of coherence of monetary measure
Level of Adequacy	Market simulations	MWh/year	€/year (market-based)	European

[38] Cf Annex IV, 2c.

6.10 Section 10: Methodology for Security of Supply: System Flexibility Benefit (B7)

Indicator definition:

- Definition: The capability of an electric system to face the system balancing energy needs in the context of high penetration levels of non-dispatchable electricity generation.
- Relevance: Cross-border interconnections can play a fundamental role in the integration of non-dispatchable energy generation as they support ramping where deviations are balanced over a power system covering a wider area. By balancing these fluctuations across larger geographic areas, the variability of RES effectively decreases and its predictability increases.

Indicator calculation:

- Model: B7.1: Market simulations; based on the projects impact on shared balancing energy. B7.2: qualitative description
- Quantitative measure: B7.1: ordinary scale ; B7.2: qualitative description
- Monetisation: monetization is not recommended until dataset and assumptions are not consolidated

Interlinkage to other CBA indicators:

- none

Introduction

This section describes the methodology for a quantitative assessment (non-monetised) of flexibility, pending methodology developments of B7.1 and B7.2.

The System flexibility indicator (B7) seeks to capture the capability of an electric system to face the system balancing energy needs in the context of high penetration levels of non-dispatchable electricity generation. These changes are expected to increase in the future, which requires more flexible conventional generation to deal with the more frequent and acute ramping-up and ramping-down requirements.

Cross-border interconnections can play a fundamental role in the integration of non-dispatchable energy generation as they support ramping where deviations are balanced over a power system covering a wider area. By balancing these fluctuations across larger geographic areas, the variability of RES effectively decreases and its predictability increases. Transmission capacity, thus, provides a form of flexibility in the system by increasing the available flexible units that can be shared between different control areas.

Storage technologies, demand-side response, and the participation of RES can also play an important role in providing flexibility to the system. While the impact of storage on flexibility is given in Chapter 4, it is not yet possible to assess the latter ones (DSR and participation of RES) in an objective way.

The true valuation of system flexibility—within the limits of a Guideline on Electricity Transmission System Operation (SOGL)—is ultimately the valuation of the system needs and means for balancing energy exchanges, to which grid development (interconnections and internal reinforcements) will have its influence.

The B7.1 indicator, and its methodology, might ultimately have to evolve in this direction—subject to satisfactory implementation, which is currently under development—in order to accurately calculate and reflect the socio-economic welfare that is expected from the mandatory exchange of balancing energy products. In this sense, ENTSO-E has started acquiring necessary data, hypothesis development, and analysis to investigate the setup of such market models.

B7.1 Balancing energy exchange (aFRR, mFRR, RR)

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.

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).

New interconnectors and internal reinforcements with cross-border impact can enable the exchange of balancing energy across national balancing markets, where cross zonal capacity remains unused after market-closure in either direction (upward and downward activations). Exchanging balancing energy will enable cheaper bids from neighbouring markets to displace more expensive bids in the local balancing market, leading to cost savings and improvement in the net welfare.

The full assessment of balancing energy exchanges can only be realised when platforms for exchanging balancing energy exist. There is a challenge when it comes to choosing the right balance between complexity and feasibility of completing assessments, timescales, and resource levels. On the other hand, producing full models for balancing energy markets may be too time-consuming. For these reasons, this benefit is addressed by qualitative assessment, as indicated in the table below.

Available approaches	Source of Calculation	Basic Unit of Measure
Balancing Energy Exchanges	Qualitative studies or principles propose	0/+/++

Where:

0: No change: the technology/project has no (or just marginal) impact on the Balancing Energy Exchanges indicator.

+: Small to moderate improvement: the technology/project has only a small impact on the Balancing Energy Exchanges indicator.

++: Significant improvement: the technology/project has a large impact on the Balancing Energy Exchanges indicator.

Additionally, a detailed description of how the qualitative indicators have been defined is given within the study specific implementation guidelines.

Methodology

The basic principle of this method is that increasing cross-border capacity could lead to an increase in balancing energy exchanges between control areas and, consequently, a reduction in balancing energy costs. The scope is to quantify this reduction in balancing cost. The expected outcome will eventually show an increase or decrease in the overall welfare of the system.

- **Common Platform**

  It is assumed that in the future there will be platforms to exchange balancing energy products, such as 'EU imbalance netting', TERRE, MARIE, and PICASSO.[39]market The balancing platforms presuppose that the settlement rules will be harmonised to marginal pricing across different markets.

  The platform also presupposes that there will be standard balancing products to be exchanged. Common balancing platforms are expected to be rolled out as part of the balancing guidelines implementation. This assumption can be tested and adjusted for projects that do not have a foreseeable common platform

- **Balancing Needs**40

  A system imbalance that needs to be resolved is assumed. The volume required varies across member states, and assumptions would be made about what this would be over the lifetime of the project being assessed. These needs are not easy to forecast as generation and consumption mix are evolving, and a cross-border project could itself increase the balancing needs across to bidding areas.

  One option could be to use historical balancing needs, making the assumption that they will apply in the future. However, as the share of RES in the energy mix and the number of interconnectors is increasing, using historical data has the risk of underestimating future balancing needs. It is strongly recommended to study the effects of this type of assumption.

[39]It is mandatory and required by Electricity Balancing Guideline (EBGL) to setup standard platforms for the exchange of balancing energy towards 2022-2023

[40] Balancing needs for upwards and downwards reserves

- **Cross-border Exchange Capacity**

  The available cross-border capacity after market-closure, which can be used to exchange balancing energy, will be determined. This capacity in both directions will be calculated as an output from the TYNDP market simulations with and without the project. The simulation results will show the remaining cross-border capacity for every hour in the modelled years that is available to exchange balancing energy between control areas.

- **Opportunity for Imbalance Netting**

  The opportunity for imbalance netting between control areas will be determined. The opportunity for imbalance netting in one direction does not necessarily require available cross-border capacity and can be achieved even if the link is fully congested for market flows. In situations where imbalance netting requires flows in the same direction as market flows, there is the need for available cross-border capacity. The model should calculate the volume of imbalance netting that is possible.

- **Balancing Bids and Offers**[41]

  The balancing bid prices stack for the different balancing markets will be established.

  There are four proposals to determine this, with increasing levels of complexity:

  - Determine the seasonal average 'balancing bid prices' using historical data;
  - Determine hourly national 'balancing bid price' curves, i.e., prices and volumes offered, using historical data;
  - Determine historical 'balancing bid price' savings exchanged through a balancing platform;
  - Determine hourly national 'balancing bid price' curves, i.e., costs and volumes offered, using forecast data that reflects changes to generation mix (taking into account the technologies available for participating in the balancing market).

- **Balancing Cost Savings**

  For imbalance netting, the cost savings will be calculated as the difference of the balancing costs with and without the project.

Monetisation

Until the dataset and assumptions needed for this indicator are not consolidated and tested, it is not recommended to assign a monetary value to this benefit.

[41] Balancing bids and offers for upwards and downwards reserves

The reporting requirements are described in the reporting sheet in Table 10.

Table 10: Reporting Sheet for this Indicator in the TYNDP

Parameter	Source of calculation[42]	Basic unit of measure	Monetary measure	Level of coherence of monetary measure
Flexibility in terms of balancing energy exchange	Market simulations	ordinal scale	not monetised	Regional/PP level

B7.2 Balancing capacity exchange/sharing (aFRR, mFRR, RR)

Qualitative description

This section describes the principles behind the aFFR, MFRR, and RR flexibility services, but does not yet put forward a specific methodology to be applied for their quantification or monetisation. To produce such a methodology will require further analysis, investigation of hypotheses, and testing within ENTSO-E. The final methodology should follow in a future updated version of this CBA guideline.

These types of services are possible and allowed within, and between, synchronous areas (SAs), when operational limits are respected. The relevant operational limits are specified in Annex VII of the System Operation Guideline (SOGL), both between LFC-blocks and between LFC-areas of the same LFC-block and specifications of Art, 175-179. Both services require the exchange of balancing energy as a precondition (see B7.1).

In case of balancing capacity exchange between LFC-blocks, for either FRR or RR, the total contracted balancing capacity remains equal in terms of total volume, but the final obligations are displaced to the another asset that can deliver it from more optimally from a price perspective (lower fuel costs).

In case of balancing capacity sharing between LFC-blocks, for either FRR or RR, the total contracted balancing capacity is lower in terms of total volume. This implies that fewer volumes are blocked from participating in other markets (wholesale DA/ID, balancing, etc.), potentially contributing to increasing overall welfare.

Specific grid development projects[43] can increase these potential welfare benefits by giving access to potentially cheaper assets that can deliver the FRR or RR service, provided the SOGL rules are respected and available cross-border capacity is guaranteed. This can then, theoretically, result in a more optimal system operation and a reduction in overall system fuel costs. The net welfare effect is, however, to be calculated and compared with the welfare calculations in other markets (e.g., wholesale) because for

[42] Cf Annex IV, 2c.

[43] Both XB-lines as internal reinforcements that resolve congestions, or limitations that would otherwise have resulted in an exclusion of this flexibility in the dimensioning or procurement stage, as described for FRR in Art 157 (g) & 159 §7 and for RR in Art 162 in SOGL

balancing capacity exchange, XB-capacity needs to be reserved, which is then no longer available for the wholesale market.

6.11 Section 11: Methodology for Security of Supply: System Stability Benefit (B8)

Indicator definition:

- Definition: The objective of including a system stability metric is to provide an indication of the change in system stability as a result of a reinforcement project, such as a new interconnection. The Security of Supply: System Stability Benefit indicator is addressed using four separate sub-indicators, namely: B8.0 Qualitative stability indicator; B8.1 Frequency stability; B8.2 Blackstart services; and B8.3 Voltage/reactive power services.

- Relevance: Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. The assessment of system stability typically requires significant additional modelling and simulations to be undertaken. The studies are by their nature complex and time consuming making them challenging to include within the TYNDP process. It is however practical to consider a simplified and generic representation of the potential impact of reinforcement on system stability based on the technology being employed.

Indicator calculation:

- Model: B8.0: qualitative measure; B8.1: based on the projects impact on ROCOF and NADIR and qualitative description; B8.2: assumed energy not supplied; B8.3: qualitative description
- Quantitative measure: see under "model"
- Monetisation: B8.0: not monetized; B8.1: not monetized; B8.2: energy not supplied costs using VOLL; B8.3: not monetized

Interlinkage to other CBA indicators:

- none

The objective of including a system stability metric is to provide an indication of the change in system stability as a result of a reinforcement project, such as a new interconnection. The Security of Supply: System Stability Benefit indicator is addressed using four separate sub-indicators, namely:

- B8.0 Qualitative stability indicator;

- B8.1 Frequency stability;
- B8.2 Blackstart services; and
- B8.3 Voltage/reactive power services.

Each of these indicators is discussed in detail below.

B8.0 QUALITATIVE STABILITY INDICATOR

Introduction

This section describes the methodology for a qualitative assessment (non-monetised) of stability, pending methodology development of B8.1–B8.3.

Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. Examples of physical disturbances could be electrical faults, load changes, generator outages, line outages, voltage collapse, or some combination of these.

The assessment of system stability typically requires significant additional modelling and simulations to be undertaken, for which the supporting models would be required. The studies are by their nature complex and time consuming making them challenging to include within the TYNDP process. It is however practical to consider a simplified and generic representation of the potential impact of reinforcement on system stability based on the technology being employed.

Methodology

System stability is addressed by qualitative assessments of Transient Stability; Voltage Stability, and Frequency Stability. For each of the technologies, the generic impact on Transient, Voltage, and Frequency Stability are indicated in the Table 11.

Table 11: Security of Supply: system stability indicator, given as qualitative indicator related to the different technologies

Element	Transient Stability	Voltage Stability	Frequency Stability
New AC line	++	++	0
New HVDC	++	++	+ (between sync areas)
AC line series compensation	+	+	0
AC line high temperature conductor/conductor replacement (e.g., duplex to triplex)	-	-	0
AC line Dynamic Line Rating	-	-	0
MSC/MSR (Mechanically Switched Capacitors/Reactors)	0	+	0
SVC	+	+	0
STATCOM	+	++	0
Synchronous condenser	+	++	++

Where:

-: Adverse effect: the technology/project has a negative impact on the respective indicator.

0: No change: the technology/project has no (or just marginal) impact on the respective indicator.

+: Small to moderate improvement: the technology/project has only a small impact on the respective indicator.

++: Significant improvement: the technology/project has a large impact on the respective indicator.

N/A: Not relevant: if a particular project is located in a region where the respective indicator is seen as not relevant,[44] this should also be highlighted by reporting as N/A.

In addition to this qualitative stability indication, Table 11 can also act as an indication of where further investigations on transient, voltage, and frequency stability might be interesting, on the one hand, and where no further information is expected on the other.

[44] This might be the case when previous to the project assessment (e.g., inside the scenario building) the needs for SoS in relation to a certain effect (transient, voltage, frequency stability), defined on a regional level, have been determined as not relevant for a certain region.

Where detailed stability simulations have been completed and the results of such technical assessments are available, they may be provided to supplement the results obtained using the qualitative table provided in Table 10. For such cases, the generic representation contained in Table 11 may be modified to appropriately represent the results of the technical studies. It is necessary that the supporting reports are provided to corroborate the assessments and any modifications to Table 11. Currently, this quantitative assessment has been made for the impact of a reinforcement project on the frequency stability.

B8.1 FREQUENCY STABILITY

Introduction

Frequency stability is defined as the ability of a power system to maintain a steady frequency within a nominal range, following mismatches between generation and demand on a continuous basis or following a severe system contingency, resulting in a significant imbalance between generation and demand.

Methodology

Frequency stability is addressed by discussing frequency quality targets and capacity sharing. These are discussed separately as follows:

- **B8.1.1 Focus on frequency quality targets (energy aspect)**

  Assuming that the frequency oscillation across the synchronous area is small and well-damped, the frequency can be considered as a uniform value toward all the nodes of the synchronous area. Under these assumptions it is possible to represent the systems with one equivalent bus and use it to estimate the system frequency behaviour of a power system for generation/load imbalances.

  Using the proposed model for frequency stability calculations, a grid reinforcement project can be evaluated.

  For HVDC interconnectors between synchronous areas:

  To assess the impact of a reinforcement project improving the frequency stability, the drop of the frequency of the system with and without the reinforcement project is compared through a set of indices over a one year period:

  - *Maximum Nadir Variation* (Δf_{MAX}), defined as the yearly maximum value of the difference of the frequency nadir for each hour of the year with and without a network enhancement project.

  - *Maximum Rocof Variation* (ΔR_{MAX}), defined as the yearly maximum value of the difference of the ROCOF for each hour of the year with and without a network enhancement project.

This list might be complemented with the list of official frequency quality criteria from the SOGL.

The computation of the indices is undertaken on an hourly basis over a timeframe of one year. The analysis is referred, at the planning level, to future systems scenarios foreseen in terms of hourly power generation by technology type and loads per European country. Considering reference values for generators, in terms of rated capacity and constant of inertia and loading levels, the running capacity necessary to generate the output power from the market simulations is determined. It is then possible to calculate the kinetic energy and primary reserve of the system necessary to perform the simulations using the single-bus model, with and without the evaluating project. Finally, the frequency stability indices can be computed. This allows for a quantitative assessment of the frequency quality (at an energy level) based on a frequency netting optimisation if exchange is implemented (cfr. Section B8.1.2).

The way the interconnector is used for FCR purposes should be reported as it must be consistent with the NTC used for the other indicators (if some capacity is reserved for FCR purposes, it cannot be used for market exchange). No monetisation can be done.

- **B8.1.2 Capacity exchange/sharing**

This section describes the principles behind these types of services, but does not yet put forward a specific methodology to be applied to arrive at quantitative/monetised results, which requires further analysis and testing. The final methodology should follow in the implementation guideline or in a future version of the CBA guideline.

Between Synchronous Areas (SAs), i.e., 'frequency coupling':

Between Synchronous Areas, frequency support services are officially known as 'frequency coupling services', as described in SOGL. From a legislative point of view, both frequency capacity exchange as well as frequency capacity sharing are allowed based on Art. 171/172 of SOGL. The allowed technical services, or products, across HVDC links between SAs are described in the ENTSOE SOC approved paper and consist of frequency netting (FN), frequency exchange (FE), and frequency optimisation (FO). These are illustrated in Figure 10:

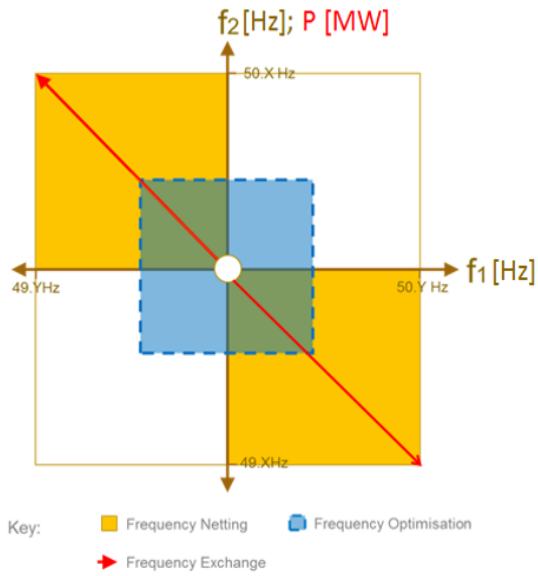


Figure 10: Illustration of the frequency netting and exchange

The specific limits and conditions to respect are described in the Synchronous Area Operational Agreements (SA-OA), which inherently cap the maximum potential of any benefits by setting up such services. The paper is in line with the stipulations set forward in Art. 171/172 of the SOGL. Across HVDC-cables, such services can indeed be implemented and unlock specific benefits that could theoretically be monetised (FCR capacity exchange or sharing) or non-monetised (general increase of frequency quality).

Frequency netting & optimisation contribute to the overall frequency quality of both connecting SAs. These benefits cannot be currently monetised in the CBA methodology, as the direct relation between frequency quality and the total amount of FCR reserves is not available. Only a qualitative assessment is possible, or quantification of the frequency quality indices. **Frequency exchange** requires physical FCR backup on the providing SA side and hence enables the exchange of FCR capacity, provided the service is 100% available over the HVDC link. Such setup could theoretically be monetised, however, a proper methodology cannot yet be proposed.

The benefits of the above described services can be unlocked by certain grid development projects that enable additional HVDC links between SAs, provided the considered project has the technical capacity to enable such services (which should be included in the CAPEX). Pending further analysis and a final methodology in the implementation guideline or the next CBA version, the assessment of those benefits could work as follows:

For frequency netting and optimisation, in cases where the frequency quality contribution is systematic, both connecting SAs could agree in a sharing agreement to reduce the overall amount of FCR obligation. This is provided that the resulting frequency quality remains within the legal limits imposed by SOGL. In case this volume could be accurately and realistically estimated, welfare benefits from other markets (SEW in DA/ID/balancing markets) can be calculated because of a reduced overall FCR obligation.

For frequency capacity exchange, the welfare benefits (SEW in DA/ID/balancing markets) are calculated by more optimally allocating the overall FCR obligation. As a cautionary note, this assumes that the allocation can be done in the most optimal way; however, in practice FCR auction clearing happens before DA clearing. Therefore, the net effect can also be negative. Frequency exchange gives access to more (potentially cheaper) resources that can provide FCR.

Within a Synchronous Area:

Within a Synchronous Area, only frequency capacity exchange is allowed (not sharing), as described in Art. 163/164 of SOGL. Limitations for the capacity exchange (Annex VI of SOGL) stipulate fixed limits of 30% of initial FCR obligations per LFC block for the CE SA, so theoretically there is no direct link to any grid development projects there– hence no direct benefits.

However, as described in other SAs (non-CE) or within LFC-areas of the same LFC-block within CE, cases where internal congestions would be alleviated, or a more even distribution of FCR can be obtained in the case of network splitting, facilitated by those potential grid development projects, benefits could be present by giving access to more or cheaper assets that can then deliver the FCR service. This could theoretically result in a more optimal system operation (reducing overall system/fuel costs). The latter is also described in Art. 154 §4 of SOGL where geographic limitations could indeed apply that exclude certain units from participating, which would, if resolved by certain grid development projects, then increase the overall optimality of the system. In order to calculate or monetise such benefits, very specific localised information should be available and integrated with other welfare calculations in DA/balancing markets, in order to determine the effective monetised benefit.

B8.2 BLACKSTART SERVICES

Introduction

This section describes the principles behind blackstart services or reserves, but does not yet put forward a specific methodology for quantitative/monetised results in a general sense; this requires further analysis and testing. However, a specific application for small systems connecting to larger systems is given below.

Blackstart reserves are contracted or imposed by TSOs to ensure that a minimum level of existing market flexible units are available for re-energising the power system after an event that results in the loss of power supply to the entirety, or part, of a bidding zone or LFC block. Such services are typically described and required by SOGL and national legislation.

Certain grid development projects (internal or cross border reinforcements) might reduce the need of the total required volume and/or unlock pathways for contracting more price-efficient units (lower fuel costs). This potentially reduces the overall system costs and contributes to overall welfare in other markets (e.g., wholesale or balancing markets) as more (typically peaking) units would become available as a result.

Methodology

Calculation of the blackstart benefits requires the definition of assumptions on the total volume of blackstart reserves (and their required localisation) that are needed for the related bidding zones/LFC blocks and the related welfare contribution that such respective projects would then bring in other markets (DA/ID wholesale, balancing, etc.) by unlocking the blackstart power capacities.

In case the overall needs are expected to increase (or the means would become insufficient to cover the need), a potential valuation could also be the avoided investment in such blackstart services. It should be clear that this type of benefit does not overlap with the adequacy indicator B.6 because, by definition. blackstart services cannot participate in any other markets (adequacy, wholesale, balancing), as they must be kept out to serve their sole purpose, which is to restore the system after a possible contingency event. The exact value is also dependent on the effective availability that specific projects could bring to such services.

Specific application: Methodology for Synchronisation with Continental Europe

In general, the more power plants that are connected to the electric power system, the more economical it is likely to be. The greater the total amount of installed capacity, the greater the likelihood that larger and more economical power plant units could be installed. To ensure that quality and reliability of supply is maintained, the largest single unit that can be in operation should normally not exceed 3% to 5% of the total system load. This is because when such generators are disconnected, they can be replaced by other existing generators in the power system within a reasonable time. Therefore, interconnected power systems can accommodate larger generating units that are more economical than small ones.

Larger energy systems have different categories of consumers. The total load of such a system is more stable. As power systems expand, the possibility for the interconnection of power systems arises, but the interconnecting systems must agree with the conditions of the control area. The resulting control area is controlled by a centralised control centre that is responsible for ensuring the following:

- The balance of power and energy;
- Schedules of inter-system power exchanges with agreed accuracy;
- The frequency in the system is adjusted within the required range; and
- Reliable operation of the required power reserve is maintained and the provision of assistance to neighbouring systems when needed (i.e., in an emergency or to carry out repairs).

There are many benefits of interconnecting electric power systems, including the following:

- The total power reserve required in the system is reduced;
- The power and energy usage of hydropower plants is improved (especially during floods) and the economy of the system is increased;
- Inter-system assistance in repairs, or in the event of an accident (e.g., the system is in extremis state), is possible;
- Inter-system assistance, due to uneven seasonal loads and power changes in the generating stations, is possible; and
- Because of the effects of longitude and latitude, the total maximum load demand of the interconnected system is reduced.

It should be noted that this indicator evaluates extended blackout risks and the consequences of such an event.

Monetisation

The calculation of benefits is carried out by calculating the total costs incurred for a total regional blackout event. The cost is estimated using energy not supplied, which depends on the average hourly consumption rate, the value of loss load, and the duration of the interruption.

The calculation is described by the following formula:

$$Energy\ not\ supplied\ cost\ (EUR) = VOLL\ (EUR/MWh) * Consumption\ (MWh/h) * Duration\ (h)$$

This evaluation method can only be applied to Baltic States or/and other pan-European countries outside European synchronous zones.

Example:

Delivering on the long-term plans of the EU (e.g., climate policy goals and targets for 2030 and 2050) will introduce significant challenges with respect to RES integration targets, levels of nonsynchronous generation, decrease in inertia, reduction in short circuit power, dynamic voltage stability, etc. These phenomena are particularly challenging for small systems (such as the Baltic States of Latvia, Estonia, and Lithuania) or poorly connected systems. The cost of mitigating these challenges will be expensive and a significant cost burden for the small or poorly connected systems. To avoid, or minimise, the impact or reduce operating costs, such systems should synchronise with continental Europe.

In the specific case of the Baltic electricity energy sector, the power system was not designed to work as an 'energy island'. It is strongly reliant on the infrastructure of neighbouring countries, which poses significant risk for the security of supply in the Baltic States and increases the risk of blackouts. Its security of supply is also impacted by broader political factors within the region.

Despite the Baltic States being integrated into the EU common internal energy market, they remain synchronously connected to their neighbouring IPS/UPS system. This hinders full integration to EU electricity markets and the European transmission grid.

B8.3 Voltage/reactive power services

Qualitative description

Voltage or reactive power services/reserves are required from a TSO point of view in order to satisfy the SOGL regulation and are also described in national legislation. Typically, these services are contracted or imposed by TSOs, for a certain minimum level, on specific locations of the grid on existing market flexible units in order to ensure the voltage quality remains within the necessary system security limits. Alternatively, these services can also be ensured by investments in passive elements (capacitors/reactors) or active elements (power electronic devices such as STATCOMs).

Certain grid development projects (internal or cross border reinforcements) might reduce the need of the total required volume of these services. This potentially avoids the need for investments and/or unlocks pathways for contracting more price-efficient units (lower fuel costs) with this technical capability, thereby potentially reducing the overall system costs and contributing to overall welfare in other markets (e.g., wholesale or balancing markets) as more units would become available as a result.

The calculation of such benefits requires the definition of assumptions regarding the total volume of reactive power reserves (and their required localisation) that are needed for the related bidding zones/LFC blocks and the related welfare contribution that such respective projects would then bring in other markets (DA/ID wholesale, balancing, etc.) by unlocking additional liquidity. In case the overall needs are expected to increase (or the means would become insufficient to cover the need), a potential valuation could also be the avoided investment for such reactive power reserves.

6.12 Section 12: Methodology for Avoidance of the Renewal/Replacement Costs of Infrastructure (B9)

Indicator definition:

- Definition: Reduction of needed costs for replacing or upgrading existing infrastructure due to new projects or investments.
- Relevance: Investing into the new project partially replaces, or as a minimum defers, the investment costs needed for the refurbishment or replacement of the existing grid equipment and, therefore, represents a saving in capital investment for the project promoter.

Indicator calculation:

- Model: Information delivered by the project promoter
- Quantitative measure: reduction of necessary costs
- Monetisation: per definition monetised

Interlinkage to other CBA indicators:

- none

Introduction

When a new project is required to meet a particular need and creates value identified by the CBA methodology, additional benefits may also arise. In some circumstances, the new project also eliminates the need for replacing or upgrading existing infrastructure at the end of its useful life, or which may be in a poor condition and in need of refurbishment in order to maintain its designed capacity. In such a case, the new project enables the project promoter to avoid the investment costs required, by the existing transmission grid, to maintain the existing level of grid reliability and security.

Investing into the new project partially replaces, or as a minimum defers, the investment costs needed for the refurbishment or replacement of the existing grid equipment and, therefore, represents a saving in capital investment for the project promoter.

Methodology

For the ability to value the savings in planned maintenance and refurbishment spending, a pre-existing asset management plan is required and would represent the reference point for the valuation. Given that the valuation should be based on existing known commitments for maintenance capital investment, the cost estimates should be known and would be based on the project promoter's own cost estimates.

The precise nature of the capacity benefit of the new project needs to be determined, and assurances are required that the security of supply is not compromised as a result of relying on the new project to satisfy the system security requirements.

Health and safety standards are not to be compromised as a result of the decision not to make further investments in maintaining the capacity or capability of existing transmission equipment.

This benefit can only be taken into account if the reference situation (to which the new project is compared to) includes the contribution of the refurbishment. Hence, the TOOT or PINT situation should be compared to a level of grid reliability and security that includes the refurbishment.

Monetisation

The benefit is modelled as a once-off incremental benefit that is specific to the circumstances of the project promoter and should, therefore, be applied only for refurbishment projects within the project promoter's network. In case of a cross-border project, a bilateral agreement between the different parties needs to be achieved. The value is monetised and represented in EUR millions. For comparison with other indicators' purposes, attention must be paid to the date at which the avoided investment would have occurred, in order to discount it properly. Moreover, there is a risk that the project promoter represent the full benefit of the refurbishment cost of existing infrastructure for the new project when, for some cases, the benefit is only a deferment of refurbishment costs. In such a case, the project promoter would have to carry the cost difference between the deferred refurbishment investments.

The reporting requirements are described in the reporting sheet in Table 12.

Table 12: Reporting Sheet for this Indicator in the TYNDP

Parameter	Source of Calculation	Basic Unit of Measure	Monetary measure	Level of Coherence
Benefit from avoidance of renewal/ replacement of infrastructure	Information delivered by project promoter	€	per definition monetary	Regional/PP level

6.13 Section 13: Reduction of Necessary Reserve for Redispatch Power Plants (B10)

Indicator definition:

- Definition: Change in needed reserves of redispatch power plants.
- Relevance: The maximum redispatch power is a direct indication of the need for reserve power plants and the difference (with and without the project) gives a direct indication of the change in needed reserve power plants.

Indicator calculation:

- Model: Redispatch simulations; based on a redispatch cost comparison with/without the project.
- Quantitative measure: this indicator is directly given in monetary values.
- Monetisation: per definition monetized and given in €/year

Interlinkage to other CBA indicators:

- B1, B2, B3, B4, B5

Introduction

This benefit indicator can only be calculated when applying redispatch simulations (for a detailed description on redispatch simulations see section 6.21) for the project assessment and must be added to the set of benefit indicators as described above.

The redispatch changes the cost-optimal dispatch by exchanging cheaper units for more expensive units. This leads to situations where more peaking units are more likely to be running. In some countries, the power plants necessary for providing the maximum redispatch capacity are provided for using specific contracts.
Therefore, the maximum redispatch power is a direct indication of the need for reserve power plants and the difference (with and without the project) gives a direct indication of the change in needed reserve power plants.

Methodology

The capacity of necessary reserves for redispatch (in MW) can be determined by performing the comparison of the maximum power of redispatch, with and without the project, as received from year-round redispatch simulations.

The maximum redispatch power is defined as the maximum of the hourly redispatch power that is calculated by summing up all redispatch actions within the respective hour.

Note: This methodology can only be applied for projects located in countries that have a specific mechanism for contracting redispatch reserve power plants or connecting countries where at least one country has such a mechanism.

Monetisation

The quantification of the benefit is relative to the reduction of the maximum amount of necessary redispatch in MW and can be monetised using statistical analysis of the costs of reserve from power plants, i.e., from changing capacity constraint payments.

Example: Internal project in country A

A fictitious example of this indicator is provided for an internal project in country A, as follows:

It is assumed that within country A, a mechanism for allocating redispatch power plants exists and that the assessment has been performed using redispatch simulations. The project is part of the reference grid so the TOOT method will be applied. The following process steps are adhered to:

1. Calculate the redispatch power with and without the project for each hour of the year

2. Find the maximum redispatch power for both cases (with and without the project):

   RD_{power}(with) = 16000 MW, which appears in hour 3465

   RD_{power}(without) = 18000 MW, which appears in hour 5687

3. Build the delta:

   RD_{power}(delta) = 18000 MW – 16000 MW = 2000 MW

4. Monetise the benefit with 20k€/MW of allocated redispatch power plant:

   B11 = 2000 MW * 20k€/MW = 40 M€

Double-counting:

The risk of double accounting is not given because this benefit indicator 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. Furthermore, even when these redispatch reserves are needed payments, the allocation payments and the actual redispatch costs have to be taken. However, within the simulations, only the latter part is taken into account, and the reduction of allocation payments need to be added to the overall project benefit.

Table 13 Reporting Sheet for this Indicator in the TYNDP

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence of Monetary Measure
Reduction of necessary reserves for redispatch power plants	Redispatch studies (substitution effect)	MW	€/yr (market-based)	National

6.14 Section 14: Methodology for CAPital EXpenditure (CAPEX) (C1)

Capital expenditure (i.e. CAPEX) is the cost of developing or delivering physical assets.

CAPEX figures are to be declared as real values (i.e. not taking into account inflation) for each investment. The values are expressed as constant year-of-study values. For example, for TYNDP 2020-30 the values are represented in constant 2020 values.

The capital expense for an investment is to be aggregated and represented as a single value in the year that it is commissioned.

Where a project is comprised of a number of investments, the aggregated real value of the expected capital expenditure for each investment and the year that the investment is to be commissioned should be provided.

The terminal values (i.e. the value of the assets at the end of the assessment period) are assumed to be zero.

The costs shall be reported according to the investment status and related uncertainties in the following way:

- For mature investments with the status of '**permitting**' or '**under construction**', costs should be reported based on the current data of project promoters, together with a clearly explained uncertainty range.[45]

- For non-mature investments in the '**planned, but not yet in permitting**' or '**under consideration**' status, the following is relevant:

  1. If detailed project cost information is available: this should be used and the same principle applied as for mature investments.

  2. If detailed project cost information is not usually available, the project promoters will be required to use standard investment costs, which will be provided by ENTSO-E in the context of the TYNDP. To account for the specific circumstances and complexities of the project, these costs are to be multiplied by a clearly defined project-specific complexity factor.

  Complexity factors are to be applied in the following manner:

[45] For example, information presented on National Investment Plans.

a. To provide a range for the standard costs per group of assets, including a maximum and minimum value according to its expectations. In this case, the project promoter is required to provide an explanation (see table 13).[46]

b. In the case where the project promoter chooses complexity factors that exceed the previous ranges, the choice should be clearly explained. For example, applying complexity factors to account for different project characteristics, such as terrain, routing, presence of historical landmarks, presence of other infrastructure, population density, special materials and designs, protected areas, etc. The complexity factor should be unbundled and applied to the specific cost categories in order to build up the project cost.

c. In the case of early phase projects, were the project promoter has limited knowledge of the project investment costs (including the effect of possible project characteristic impacts), these costs should be equal to the standard investment costs using a complexity factor equal to 1.0.[47]

Finally, the investment costs will be one value to which an uncertainty range is applied.

The range of complexity factors to be applied per asset class is shown in Table 14.

Table 14 Table of maximum and minimum Complexity Factors per group of assets

Investment type	Maximum CF	Minimum CF
AC Onshore Overhead Lines (OHL)	1.30	0.50
AC Onshore Cable	1.20	0.70
Subsea Cables	1.10	0.90
AC Substation	1.30	0.60
Transformer	1.30	0.70
HVDC Converter Station	1.20	0.90

The provision of the CAPEX expenses in this way permits the comparison of the project with other projects as they can be discounted using common assumptions to the point in time for which the assessment is needed (the year in which the study is performed). This step is not requested of the promoter.

CAPEX includes both the capital costs incurred at inception during the construction period; and capital expenditure incurred later in the project life-cycle. Two indicators, C1a and C1b, which represent the asset costs at inception and the on-going asset costs during the original assets' operation respectively, therefore represent CAPEX.

[46] Taken, for example, from the ACER report, with minimum and maximum interquartiles.
[47] This information will be updated in future TYNDPs when project promoters have more detail.

C1a: Inception CAPEX

Inception CAPEX is the capital costs incurred at the inception of the project (i.e. during the construction period). It includes the following cost categories:

- Costs for permits, feasibility studies, design, and land acquisition;
- Costs for equipment, materials, and execution (such as towers, foundations, conductors, substations, protection, and control systems;
- Costs for temporary solutions that are necessary to realise a project (e.g., a new overhead line required in an existing route or installation of a temporary circuit during the construction period); and
- Expected environmental and consenting costs (such as costs to avoid, environmental impacts or costs compensated under existing legal provisions, cost of planning procedures).

Example: Project X, which is a cluster of investments A, B, and C

For each investment the promoter should provide the aggregated real value (i.e., excluding inflation rate) of the expected capital expenditure for the investment and the year that the investment is to be commissioned. This is illustrated by Project X, which is a cluster of three investments: investment A, investment B, and investment C. Investment A is expected to be commissioned in 2022, whereas investments B and C are expected to be commissioned in 2023 and 2024, respectively.

The assumption for Project X is that capital expenses for each investment are aggregated and represented as a single value in the year that it is commissioned.

The project promoter should, therefore, provide the information as illustrated in Table 15.

Table 15: Illustration of Capital Expenditure Information to be provided by Project Promoters

Investment	CAPEX [M€]	Year of Commission
Investment A	40*	2022
Investment B	10*	2023
Investment C	20*	2024

[Note*: the investment costs are real values in 2020 (for TYNDP 2020-30) terms]

C1b: Sustaining CAPEX

Sustaining CAPEX is the capital expenditure incurred during the assessment period that is necessary to ensure that the functionality of the original assets realised by the inception CAPEX is maintained. This includes the following:

- Mid-life interventions or significant and scheduled upgrade of assets that are CAPEX in nature are also to be included in the evaluation. This would include the expected costs for devices that have to be replaced within the assessment period (consideration of project life-cycle).

- Dismantling costs at the end of the equipment life-cycle, where relevant, are also to be included in the CAPEX cost figures.

All costs falling outside the assessment period are not to be considered. This impacts for example the dismantling costs for projects with lifetimes longer than the assessment period.

6.15 Section 15: Methodology for OPerating EXpenditure (OPEX) (C2)

Operating Expenditure, or OPEX, is the on-going cost of running the investment or project over the assessment period.

OPEX is represented as an annual average cost. The OPEX is applied annually from the first year after commissioning for the duration of the assessment period.

As mentioned in Section 3, the values are real values and are to be reported as constant year-of-study values. For example, for the TYNDP 2020 the values are to be represented as constant 2020 values.

The following costs are to be considered as OPEX:

- Expected annual maintenance costs.
- Expected annual operation costs.

It is required that OPEX is reported per investment.

It is important to highlight that some annual costs can mistakenly be considered as a component of OPEX, but **do not** fall into this category, namely:

- System losses, as they are taken into account in a dedicated indicator; and
- The cost of purchasing energy for storage investments, as they are an internal variables for the SEW computation.

6.16 Section 16: General Statements on Residual Impacts

As the main objective of transmission system planning is to ensure the development of an adequate transmission system that:

- Enables safe system operation;
- Enables a high level of security of supply;
- Contributes to a sustainable energy supply;
- Facilitates grid access for all market participants;
- Contributes to internal market integration, facilitates competition and harmonisation;
- Contributes to improving the energy efficiency of the system; and
- Enables cross-country transmissions.

The TYNDP highlights the way transmission projects of European Significance contribute to the EU's overall sustainability goals, such as CO_2 reduction or integration of renewable energy sources (RES). On a local level, these projects may also impact other EU sustainability objectives, such as the EU Biodiversity Strategy (COM 2011 244) and landscape protection policies (European Landscape Convention). Moreover, new infrastructure needs to be carefully implemented though appropriate public participation at different stages of the project, taking into account the goals of the Aarhus Convention (1998) and the measures foreseen by the Regulation on Guidelines for trans-European energy infrastructure (EU n° 347-2013).

As a rule, the first measure to deal with the potential negative social and environmental effects of a project is to avoid causing the impact (e.g., through routing decisions) whenever possible. Steps are also taken to minimise impacts through mitigation measures, and in some instances compensatory measures, such as creation of a wildlife habitat, may be a legal requirement. When project planning is in a sufficiently advanced stage, the cost of such measures can be estimated accurately, and they are incorporated in to the total project costs (listed under indicator C1).

As it is not always possible to (fully) mitigate certain negative effects, the indicators 'social impact' and 'environmental impact' are used to:

- Indicate where potential impacts have not yet been internalised, i.e., where additional expenditures may be necessary to avoid, mitigate, and/or compensate for impacts, but where these cannot yet be estimated with enough accuracy for the costs to be included in indicator C1.
- Indicate the *residual* social and environmental effects of projects, i.e., effects that may not be fully mitigated in the final project design and cannot be objectively monetised;

Particularly in the early stages of a project, it may not be clear whether certain impacts can, and will, eventually be mitigated. Such potential impacts are included and labelled as *potential impacts*. In subsequent iterations of the TYNDP they may disappear if they are mitigated or compensated for or lose the status of *potential* impact (and become *residual*) if it becomes clear that the impact will eventually not be mitigated or compensated for.

When insufficient information is available to indicate the (potential) impacts of a project, this will be made clear in the presentation of project impacts in such a manner that 'no information' cannot be confused with 'no impact'.

In its report on *Strategic Environmental Assessment for Power Developments*, the International Council on Large Electric Systems (CIGRÉ, 2011) provides an extensive overview of factors that are relevant for performing Strategic Environmental Assessment (SEA) on transmission systems. Most indicators in this report were already covered by ENTSO-E's cost-benefit analysis guideline, either implicitly via the additional cost their mitigation creates for a project or explicitly in the form of a separate indicator (eg., CO_2 emissions). However, three aspects ('biodiversity', 'landscape', and 'social integration of infrastructure') could not be quantified clearly or objectively via an indicator or through monetisation. Previously, these were addressed in the TYNDP by an expert assessment of the risk of delays to projects, based on the likelihood of protests and objections to their social and environmental impacts. Particularly for projects that are in an early stage of development, this approach improves assessment transparency as it provides a quantitative basis for the indicator score.

To provide a meaningful, yet simple and quantifiable, measure for these impacts, the new methodology improves on this indicator by giving an estimate of the number of kilometres required for a new overhead line (OHL), underground cable (UGC), or submarine cable (SMC) that might have to be located in an area that is sensitive for its nature or biodiversity (environmental impact) or its landscape or social value (social impact) (for a definition of 'sensitive' see below).

When first identifying the need for additional transmission capacity between two areas, one may have a general idea about the areas that will be connected, while more detailed information on, for instance, the exact route of such an expansion is still lacking, as routing decisions are not taken until a later stage. In the early stages of a project, it is often difficult to determine anything concrete about the social and environmental consequences of a project, let alone determine the cost of mitigation measures to counter such effects. Therefore, the quantification of these indicators will be presented in the form of a range, of which the 'bandwidth' tends to decrease as the project progresses in time and information increases. In the very early stages of development, it is possible that the indicators are left blank in the TYNDP and are only scored in a successive version of the TYNDP when some preliminary studies have been carried out and there is at least some information available to base such scoring upon. A strength of this type of measure is that it can be applied at rather early stages of a project, when the environmental and social impact of projects is generally not very clear and mitigation measures cannot yet be defined. In subsequent iterations of the TYNDP, as route planning advances and specification of mitigation measures becomes clearer, the costs will be internalised in 'project costs' (C1) or indicated as 'residual' impacts.

As soon as a global idea of the alternative routes that can be used has been determined, a range with minimum and maximum values for this indicator can be established. These indicators will be presented in the TYNDP along with the other indicators, as specified in ENTSO-E's CBA guideline, with a link to further information. The scores for social and environmental impact will not be presented in the TYNDP by means of a colour code. These impacts are highly project-specific and it is difficult to express these completely, objectively, and uniformly on the basis of a single indicator. This consideration has led to the use of ‘number of kilometres’ as a measure to provide information about projects in a uniform manner, while respecting the complexity of the underlying factors that make up the indicators. Attaching a colour code purely on the basis of the notion ‘number of kilometres’ would imply that a ‘final verdict’ had been passed regarding the social and environmental sensitivity of the project, which would not be correct because the number of kilometres that a line crosses through a sensitive area is only one aspect of a project's true social and environmental impact.

In the case of a replacement project, a residual impact indicator can also attain a zero or negative (i.e., having a beneficial environmental or social impact) when the affected sensitive area is reduced by the project, i.e., the ‘number of kilometres’ will become zero or negative.

6.17 Section 17: Methodology for Residual Environmental Impact (S1)

Introduction

Environmental impact characterises the local impact of the project on nature and biodiversity, as assessed through preliminary studies.

This indicator only takes into account the residual impact of a project, i.e., the portion of impact that is not fully accounted for under C1 and C2. It is expressed in terms of the number of kilometres that an overhead line or underground/submarine cable may run through environmentally 'sensitive' areas, as defined in Section 16: General Statements on Residual Impacts.

For storage projects, these indicators are less well defined and have to be examined on a project-by-project basis.

Methodology

The residual environmental impact is described using the following three descriptors:

- Stage: Refers to the stage of the project or investment. This is important as it gives an indication of the extent and accuracy at which the environmental impacts can be measured.
- Potential impact: Refers to the assessment of the potential effects that the infrastructure associated with a project or investment will have on nature and biodiversity.[48] It is measured by the distance (km) that the infrastructure will be located within an environmentally sensitive area.
- Type of sensitivity: Defines why this area is considered sensitive.

The assessment of impacts that may qualify an area as environmentally 'sensitive' for the construction of overhead lines or underground cables, specifically with regard to biodiversity, are addressed by the following Directives or International Laws:

- Habitats Directive (92/43/EEC);
- Birds Directive (2009/147/EC);
- RAMSAR site;
- IUCN key biodiversity areas;
- Marin Strategy Framework Directive (2008/56/EC); and

[48] The EC has formulated its headline target for 2020 that 'Halting the loss of biodiversity and the degradation of ecosystem services in the EU by 2020, and restoring them in so far as feasible, while stepping up the EU contribution to averting global biodiversity loss.'

- Other nature protection areas under national law.

Example: Assessment of hypothetical investments A, B, C, and D

The residual environmental impact of four hypothetical investments (i.e., A, B, C, and D) is illustrated in the table below:

Investment	Stage	Impact (Distance within environmentally sensitive area) [km]	Sensitivity type	Further information (Link to be provided)
A	Planned	Yes (a. 50 to 75 km; b. 30 to 40 km)	a. Birds Directive b. Habitats Directive	eg., Big Hill SPA (www….)
B	Permitting	No		(www….)
C	Planned	Yes (20 km)	Habitats Directive	(www….)
D	Under consideration	N.A	N.A	(www….)

For mature investments in the '**permitting'** or '**under construction'** status the elements listed should be reported based on the current data of the project promoter, together with the reference to the environmental impact assessment performed to identify those elements.

For non-mature investments (classified as '**planned, but not yet in permitting**' and '**under consideration**') two cases can be distinguished. If the elements mentioned are available because of an environmental assessment already performed by the promoter or competent NRA (National Regulatory Authority), they should be reported as in the case of mature investments. In all other cases, where an environmental assessment study is not available or not fit to provide the necessary elements, in the context of the TYNDP, ENTSO-E should specify (in a dedicated space of the project sheet): given that the actual route of the project might not be defined due to the low degree of maturity of its investment(s), an environmental assessment is not yet available.

6.18 Section 18: Methodology for Residual Social impact (S2)

Introduction

Social impact characterises the project impact on the local population, as assessed through preliminary studies. It is expressed in terms of the number of kilometres that an overhead line or underground/submarine cable may run through socially sensitive areas, as defined in Section 16: General Statements on Residual Impacts. This indicator only takes into account the residual impact of a project, i.e., the portion of impact that is not fully accounted for under C1 and C2. As for the environmental impact, these indicators are less well defined for storage projects and must be examined on a project-by-project basis.

Methodology

The residual environmental impact is described using the following three descriptors:

- Stage: Refers to the stage of development of the project or investment. This is important as it gives an indication of the extent to which social impact can be measured at a particular moment.
- Potential impact: Refers to the assessment of the potential effects that the infrastructure associated with the project or investment will have on densely populated or protected areas in its proximity. It is measured by the distance (km) of the infrastructure that is located within socially sensitive areas.
- Type of sensitivity: Defines why this area is considered to be sensitive.

The following definitions provide an overview of impacts that may qualify an area to be socially 'sensitive', with respect to the construction of an overhead line or underground cable:

<u>Social impact</u>

- Sensitivity regarding population density:
  - Land that is close to densely populated areas (as defined by national legislation). As a general guidance, a dense area is an area where population density is superior to the national mean.
  - Land that is near to schools, day-care centres, or similar facilities.
- Sensitivity regarding landscape: protected under the following Directives or International Laws:
  - World heritage;
  - Land within national parks and areas of outstanding natural beauty;
  - Land with cultural significance; and

- Other areas protected by national law.

Example: Assessment of hypothetical investments A, B, C, and D

The residual social impact of four hypothetical investments (i.e., A, B, C, and D) is illustrated in the table below:

Investment	Stage	Impact (Distance within environmentally sensitive area) [km]	Sensitivity Type	Further information (Link to be provided)
A	Permitting	Yes (20 to 40 km)	Dense area	(www….)
B	Planned	Yes (100 km)	European Landscape Convention	(www…)
C	Planned	No	Submarine cable	(www….)
D	Under construction	Yes (50 km)	Dense area, OHL	(www….)

For mature investments in the **'permitting'** or **'under construction'** status, the elements listed should be reported based on the current data of the project promoter, together with the reference to the social impact assessment performed to identify those elements.

For non-mature investments (classified as '**planned, but not yet in permitting**' and as '**under consideration**') two cases can be distinguished. If the elements mentioned are available because a social assessment already been performed by the promoter or competent NRA (National Regulatory Authority), they should be reported as in the case of mature investments. In all other cases, where a social assessment study is not available or not fit to provide the necessary elements, then ENTSO-E, in the context of the TYNDP, should specifiy this in a dedicated space of the project sheet. The note should state: given that the actual route of the project might not be defined yet because of the low degree of maturity of its investment(s), a residual social impact assessment is not yet available.

6.19 Section 19: Methodology for Other Residual Impact (S3)

The Other Residual Impact (S3) indicator lists the impact(s) of a project that are not covered by indicators S1 and S2. These impacts may be positive or negative.

Submitting these other impacts is the responsibility of the project promoter and will be included as a list in the TYNDP assessment results.

Impacts that are accounted for by indicators S1 or S2 should not be included under this indicator.

6.20 Section 20: Assessment of Storage Projects

Introduction

The assessment used for storage projects is the same as that used for transmission projects. Storage project assessments shall use the same boundary conditions, parameters, overall assessment, and sensitivity analysis techniques that are used for transmission projects.

Furthermore it is needed to display the respective modelling parameter and assumptions for storage plants within the respective study.

In particular, if the storage project belongs to the Reference Grid (depending on how, and according to which criteria, the reference grid has been built) the TOOT methodology implies that the assessment will be carried out including all storage projects outlined in the TYNDP that are eventually included in the reference grid built for the study, taking out one storage project at the time in order to assess its benefits. Otherwise, if the project does not belong to the reference grid, a PINT approach is applied.

Methodology

The methodology performed shall be used for storage project appraisals carried out for the TYNDP and for individual storage project appraisals undertaken by TSOs or project promoters.

With respect to the individual indicators, the following applies:

- **B1. Socio-economic welfare:**

  The impact of storage on socio-economic welfare is the main benefit of large-scale storage that is claimed. In fact, the use of storage systems on the network can generate opportunities in terms of generation portfolio optimisation (arbitrage) and congestion solutions that imply cost savings on users of whole transmission systems. Market studies will be able to assess this value based on a time resolution, which is consistent with the time step used in market models. Indeed, storage can take advantage of the differences in peak and off-peak electricity prices between time steps; electricity can be stored at times when prices are low and then offered back to the system when the price of energy is higher, thereby increasing socio-economic welfare. Provided that the storage project is properly modelled, the same methodology is applied to assess this indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

- **B2. Additional societal benefit due to CO2 variation**:

  As for transmission, the CO_2 indicator is directly derived from the ability of the storage device to impact generation portfolio optimisation. The societal part can be achieved using the same methodology as described in the dedicated section for transmission projects. Provided that the storage project is properly modelled, the same methodology is applied to assess this indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

- **B3. RES integration:**

Storage devices provide resources for the electricity system to manage RES generation and, in particular, to deal with intermittent generation sources. As for transmission, this service will be measured by avoided spillage, using market studies or network studies, and its economic value is internalised in socio-economic welfare. Provided that the storage project is properly modelled, the same methodology is applied to assess this indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

- **B4. Non-direct greenhouse emission Benefit:**

As for transmission, this indicator can be determined using the same methodology as described under the B4 indicator. Provided that the storage project is properly modelled, the same methodology is applied to assess this indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

- **B5. Variation in grid losses:**

Depending on the location, the technology and the services provided by storage may increase or decrease losses in the system. This effect is measured by network studies. Provided that the storage project is properly modelled, the same methodology is applied to assess this indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

- **B6/B7. Security of supply – adequacy to meet demand and system flexibility:**

The security of supply indicators for storage follow the same principles as for the transmission projects, covering the benefit to system adequacy to meet demand (B6) combined with the increase in system flexibility (B7).

Energy storage may improve security of supply by smoothing the load pattern (‘peak shaving’), increasing off-peak load (storing the energy during periods of low energy demand) and lowering peak load (dropping it during highest demand periods). Market studies will account for the value provided at the level of a European Region (specific cases of very large storage devices).

Provided that the storage project is properly modelled, the same methodology is applied to assess the B6 indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

With regard to the benefits on the system flexibility of a storage project, it is recommended to use a qualitative approach based on table 14. This assessment is to be based on the expert view, considering the existing studies and technology information.

The qualitative assessment of storage projects is defined in Table 16.

Table 16 Qualitative assessment of System Flexibility Benefits o af storage project

KPI	Score	Motivation
Response time – FCR[49]	0 = more than 30 s + = less than 30 s ++ = less than 1 s	30 s : ramp time of FCR 1 s : typical inertia time scale
Response time – including delay time of IT and control systems	0 = more than 200 s + = less than 200 s ++ = less than 30 s	200 s: FRR[50] ramp time 30 s: FCR ramp time
Duration at rated power – total time during which available power can be sustained	0 = less than 1 min + = less than 15 min ++ = 15 min or more	1 min : double the response time of FCR 15 min : Typical PTU[51] size
Available power – power that is continuously available within the activation time	0 = 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
Ability to facilitate sharing of balancing services on wider geographical areas, including between synchronous areas		Suggestion to remove, as this is too specific and difficult to quantify

- **B8. Security of supply – system stability:**

  Storage also has costs and environmental impact. The same indicators as in the main document will be used.

- **B9. Avoidance of the Renewal/Replacement Costs of Infrastructure:**

  This indicator can be applied in the same way as for transmission projects described in Section 12: Methodology for Avoidance of the Renewal/Replacement Costs of Infrastructure (B9). Provided that the storage project is properly modelled, the same methodology is applied to assess this indicator: no specificities are foreseen for the calculation of this indicator compared to transmission.

[49] FCR = frequency containment reserve

[50] FRR = frequency restoration reserve

[51] PTU = program time unit

- **B10. Reduction of Necessary Reserves for Redispatch Power Plants (only applicable when redisptach simulations have been performed):**

  In case the benefit for storage is calculated using the redispatch approach, as described in Section 21: Redispatch simulations for project assessment, this indicator can be applied in the same way as for transmission projects, described in 6.13.

- **C1./C2.Total project expenditure:**

  Total project expenditure of storage includes investment costs, costs of operation and maintenance during the project lifecycle, as well as environmental costs (compensations, dismantling costs, etc.).

- **S1. Residual Environmental impact:**

  The environmental impact of a storage project is different from transmission, and highly dependent on technology. The assessment must take into account national legal provisions regarding environmental impact assessment and mitigation measures.

- **S2. Residual Social impact**:

  The social impact of a storage project is different from transmission, and highly dependent on technology. The assessment must take into account national legal provisions regarding social impact assessment and mitigation measures.

- **S3. Other residual impacts:**

  This indicator lists the impact(s) of a project that are not covered by indicators S1 and S2. These impacts may be positive or negative. Submitting other impacts is the responsibility of the project promoter.

6.21 Section 21: Redispatch simulations for project assessment

Assessing projects by only focusing on the impact of transfer capacities across certain international borders can lead to an underestimation of the project-specific benefits. This is because most projects also show significant positive benefits that cannot be covered by only increasing the capacities of a certain border, i.e., the reduction of internal congestions. This effect is strongest, but not limited to, internal projects that do not necessarily aim for increasing the capacities across specific borders and, therefore, this makes it difficult, or even impossible, to solely assess them using market simulations.

According to the CBA, both internal and cross-border projects can be of pan-European relevance; however, they all develop GTC over a certain boundary (and sometimes several boundaries), which may or not be an international border.

Furthermore, as cross border projects can also have an impact on internal congestions and on the redispatch, just as internal projects can have an impact on cross border transfer capacities, the application of redispatch simulations also needs to be allowed for interconnectors whenever needed.

The detailed description of the respective methodology is described below.

Generally, in order to perform the project assessment using redispatch simulations, the following simulation steps need to be performed:

- Simulation step 1: Perform market simulations to determine the cost-optimal power plant dispatch;
- Simulation step 1: Perform load-flow simulations to determine the line loadings in the observed grid; and
- Simulation step 3: Perform redispatch simulations to identify opportunities to mitigate possible congestions[52] by redispatching the initial power plant dispatch.

These steps might be performed using a single tool or a combination of different tools, but none of them must be neglected.

To perform the redispatch simulations, the same delta approach that is used for market simulations can also be applied, i.e., the benefits are calculated using TOOT or PINT and multiple TOOT or PINT.

The redispatch simulations must be aligned with the market studies that were conducted using the respective scenarios. In order to meet this requirement, the market study results (e.g., hourly generation of the specific unit types) and market study inputs (e.g., capacities of generation types) must be used as an input for the redispatch assessment. This should include the same main input data-set that was used for market simulations, which is summarised below:

[52] The check whether the congestions have been mitigated by the redispatch needs to be achieved using load-flow simulations

- Price assumptions (fuel prices, CO_2 price, and the marginal costs of thermal generation types calculated from these);

- Net generating capacities for thermal generation types, RES (wind and solar), other RES, other Non-RES, and hydro categories (incl. pumping capacities);

- Must-run values of thermal generation types;

- Availability of generating units;

- DSR capacities;

- Demand time series; and

- Fixed exchanges with non-modelled countries.

The main datasets to be used from the market simulation results are as follows:

- Utilisation (hourly time-series) of thermal generation types, DSR, and hydro categories (turbining and pumping);

- Dumped energy time series (on wind, solar, Other RES, and Other non-RES generation categories combined);

- Hourly marginal costs on market nodes; and

- ENS (energy not served) time series.

There are a number of requirements for the grid or network simulations: The simulations should ideally be based on AC load flows. If this is not possible, or in order to reduce the simulation time to an accepted level, DC load-flows can be applied. The simulations should be made on a year-round basis. If this is not possible, representative points in time can be used, as is the case for the losses calculation. The method of mapping the market simulation results to the grid model (i.e., distribution of market node level results to nodal level in the grid model) is to be defined in the Implementation Guidelines and must be consistent with other grid studies (e.g., the NTC, losses calculations).

Any thermal overloads identified from the network simulations could potentially be mitigated by employing redispatch simulations. The redispatch simulations need to observe the following requirements:

- The balance of the system must be kept (i.e., the rise in generation must be covered by the same amount of reduced generation);

- The network, or at least pre-defined critical branches, must be free of congestion after the redispatch is implemented; and

- The redispatch must be implemented in a cost-optimal way.

The perimeter of the redispatch simulations needs to be defined, and can be defined as follows:

- The perimeter should be chosen to cover the grid area influenced by the project. The decision depends on whether the project is internal or cross-border. For internal projects, the perimeter for internal projects without significant cross-border impact is typically the country that includes the project. For cross-border projects, the perimeter is typically the two countries that include the project on their common border.

- In cases where only part of the country (or countries) is influenced by the project, it is possible to reduce the perimeter to that part alone, on condition that the reduced perimeter includes all grid elements relevant for the redispatch analysis. The 'relevance' has to be clearly stated and reported.

- In cases where other surrounding countries are also supposed to be significantly influenced by the project, the perimeter should be extended to include those countries.

Optimisation measures are implemented according to a particular order. The order[53] (or sequence) that is to be applied and adhered to is as follows:

1. Apply operational measures (e.g., PST, HVDC);

2. Apply the pre-defined set of topological curative actions for each N-1 (or appropriate security criterion);

3. Optimise thermal power plants based on the dispatch costs of each generator;

4. Optimise storage devices (e.g., hydro generators, batteries, P2G, etc.);

5. Optimise RES;

6. Optimise cross-border power plants and cross-border HVDC links (depending on the perimeter); and

7. Address overloading of transmission equipment.

As there are different project types, with different objectives, the simulation methods can also be different, depending on the objective. While the objective of cross-border projects may be to increase the capacity between different countries and market areas, the objective of an internal project may not be to impact cross-border capacity. Therefore, it would make only little sense to assess these types of projects by comparing the two different market simulation runs.

[53] No country specific differences to this approach have yet been identified. If these are identified, they must be taken into account.

To account for different project types there are two options for applying redispatch simulations:

The first option only uses redispatch simulations[54] to calculate the benefits, whereas the second option integrates both market and redispatch modelling. The decision regarding which methodology to apply depends on the case being assessed. In general, when assessing the market benefits of a project where the main aim of the project relies on a cross border level, pure market simulations should be used. For projects with the main focus being in healing internal congestions, pure redispatch simulations should be used. Of course there are also projects that are built to fulfil both needs. Therefore, in order to cover the full spectrum of benefits for different types of projects, a variation in methodologies or a combination of methodologies should be used. The choice of which method to use is for the project promoter to decide. However, the chosen method needs to be displayed with a justification of the respective choice. In cases where the assessment uses a combination of market and redispatch studies, the benefits must be displayed separately for market and redispatch studies.

The indicators that can be calculated using redispatch simulations are those defined under the respective indicator.

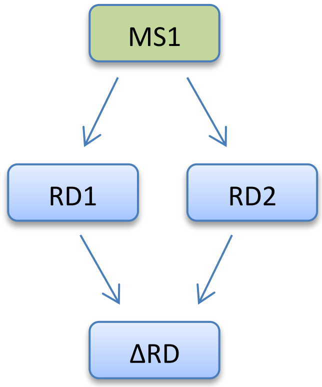
Note:

The following options are only related to the benefit calculation itself; in order to be able to perform redispatch simulations, preceding market and network simulations are always necessary.

Option 1: Calculation of benefits using pure redispatch:

The benefits for projects with a focus mainly on internal impacts can solely be assessed by using redispatch simulations. Using a single market simulation output, two different redispatch simulations (i.e., one with the project and the other without the project) need to be performed (TOOT/PINT). The process needs to respect the conditions that have been described above, and is illustrated below:

[54] The basis for the redispatch simulation under this option also relies on market simulations. In this case, the project has no NTC impact, therefore, only the reference market simulation output is used as an input. The different amounts of redispatch needed with and without the project (in the grid model) make the basis of the assessment.



Where:

MS1 refers to market simulation reference NTCs;

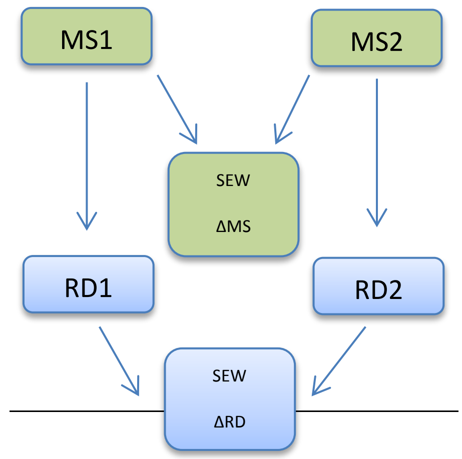
RD1 refers to the redispatch run with reference network;

RD2 refers to the redispatch run, with the project being assessed taken out/in (TOOT/PINT); and

ΔRD refers to the difference between RD1 and RD2 unit commitment (different generation costs, different CO_2 outputs, etc.)

Option 2: Calculation of benefits using a combination of border-NTC-variation and redispatch:

The benefits of some projects mainly depend on internal bottlenecks, but can also have significant cross-border impact. In this case a two-step approach can be used by combining the assessment using market simulations with redispatch simulations, with the final result being the sum of both. The process is illustrated in below:



Where:

MS1 refers to the market simulation with reference network;

MS2 refers to the market simulation with the project being assessed taken out/in (TOOT/PINT);

ΔMS refers to the difference between MS1 and MS2 unit commitment;

RD1 refers to the redispatch run with reference network;

RD2 refers to the redispatch run with the project being assessed taken out/in (TOOT/PINT);

ΔRD refers to the difference between RD1 and RD2 unit commitment; and

ΔTOTAL is given by the sum of ΔRD and ΔMS.

The application of redispatch enables the identification of a specific benefit indicator, Section 13: Reduction of Necessary Reserve for Redispatch Power Plants (B10), which is discussed in section 6.13.

6.22 Section 22: Example of ΔNTC calculation

An example is provided below to illustrate how to calculate the ΔNTC. The example uses the TOOT approach for one time step. The PINT approach is similar, only the position of the project towards the reference network model changes.

The example is designed for a ΔNTC calculation across any boundary between bidding zones.[55] This methodology should be performed over all the time steps of the year in order to calculate an annual ΔNTC to be used for simulations.

Consider the example system as presented below. The following steps must be followed:

- Step 1: Perform load flow analysis on the reference network model in line with the security criteria that take into account the N-1 criterion.

- Step 2: Identify the total generation in zone X and Y (in the simple example zone Z does not have any generation or demand), which corresponds with at least one line loaded at exactly 100% under N-1 condition (100% situation) in one of the areas around the border under consideration (i.e., X and Y in the example), and with no other congestion, under the assumption that there are no congestions in zone Z. The 100%-situation can be created by performing a generation power-shift[56] in zones X and Y (and vice versa).[57]

- Step 3: Repeat steps 1 and 2 on the reference network model from which the project has been removed (TOOT of the project for which the ΔNTC shall be determined). This will provide the values for generation in X and Y in the situation when one of the lines is loaded at exactly 100% under N-1 without the project.

- Step 4: Calculate the ΔNTC as the difference between the generation situations that correspond with the 100%-situations: ΔNTC equals the power shift.

- Step 5: Apply this process to both directions of power-flow across the boundary under analysis.

[55] In principle, the method can also be applied to any type of boundary.

[56] Which generators to use for the generation power-shift is highly context dependent. As many different methods for the generation power-shift can be applied without the possibility of identifying a preferable one, no favoured methodology for the generation power-shift is given in this guideline. But it should be mentioned that the generation power-shift can have a significant impact on the results and should, therefore, be chosen carefully and with a detailed justification. In the likely case where the initial highest N-1 load may be higher or lower that 100%, a power shift relative to the initial dispatch across the boundary is to be applied in order to reach100% and find the corresponding power value. Depending on the initial conditions, this power-shift would increase or reduce the reference power-flow.

[57] If not possible, a load power-shift could also be performed

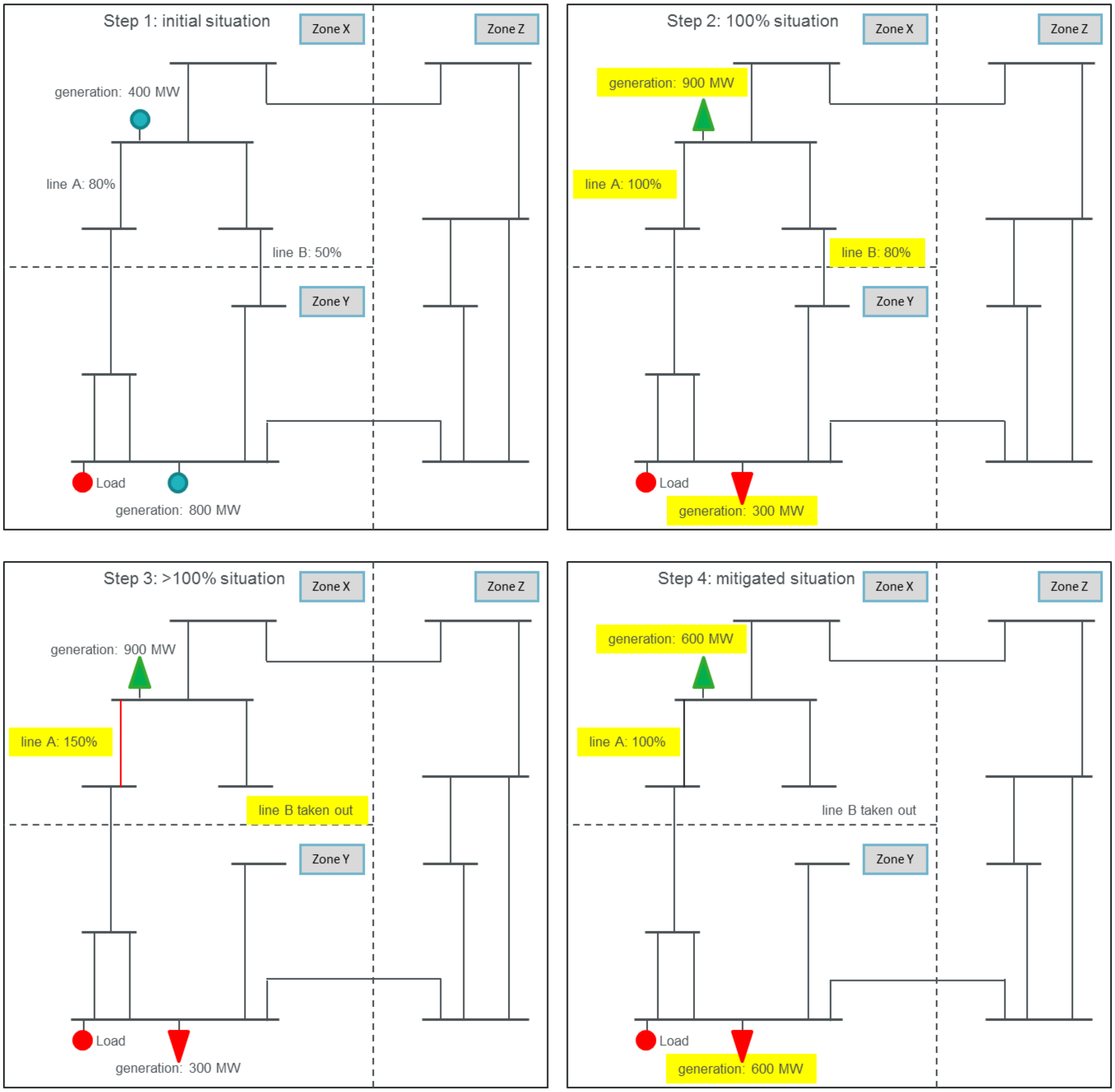


Figure 11: Qualitative example to illustrate the single steps, as described in the example above. It should be noted that the real physical flow will also have a component across the boundary between zones X-Z and Z-Y.

The results of the calculations described in the steps above are illustrated in From below.

Table 16: Simplified example of ΔNTC increase from direction X to Y across a boundary

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**
Incident	Line B in	Line B in	TOOT line B	TOOT line B	Δ NTC X > Y [MW]
Situation	initial situation	100% situation	>100% situation	mitigated situation, thus back to 100%	
Generation in zone X	400	900	900	600	300
Generation in zone Y	800	300	300	600	
demand to be covered	1200	1200	1200	1200	
Line loading at line A	80%	100%	150%	100%	
Line loading at line B	50%	80%	-	-	

From the table above, it can be seen that:

- Step 1 denotes the initial situation where all projects are put in (including line B). No overloads show up, illustrated by the line loadings in %.
- In Step 2, the generation power-shift has been done until on line is loaded at exact 100% (line A in this example) under N-1 conditions. The power-shift-volume needed was 500 MW.
- In Step 3, line B is taken out as per TOOT approach. The dispatch is fixed as it was after Step 2, with +500 MW in zone X and -500 MW in zone Y. The loading of line A became 150% (N-1).
- In Step 4, the generation power-shift is done in the opposite direction to that done in Step 2. This reduces the load on line A to 100% (N-1). The remaining power-shift, compared to the initial situation, is 200 MW. Hence, the project enables a power-shift increase of difference between initial dispatch and final dispatch; thus, 500 MW – 200 MW = 300 MW.
- Step 5 illustrates the corresponding ΔNTC in the direction of X > Y across the boundary.

6.23 Section 23: Impact on market power

The Regulation (EU) n.347/2013 project requires that this CBA guideline takes into account the impact of transmission infrastructures on market power in Member States.

Market power is the ability to alter prices away from competitive levels. It is important to point out that this ability is a reflection of potential. A market player can have market power without using it. Only when it is actually used, market power has negative consequences on socio-economic welfare by reducing the overall economic surplus to the benefit of a single market player.

Taking into account market power in a CBA, therefore, requires three steps:

- To define a market power index, which requires choosing an index among existing possibilities, such as Residual Supply Index (RSI) or Herfindahl-Hirschman Index (HHI). Each of these has its advantages and disadvantages.

- To define carefully which asset(s) will be assessed. The calculation of the index will be made with and without this object, and the difference of these two calculations will be the outcome of the CBA.

- To define the market on which the index will be applied: geographic extension, how to take into account interconnections and market coupling, treatment of regulated market segments, market products to consider.

All of these choices affect the results of a market power analysis, i.e., the perceived market power is highly dependent on how it is defined.

It must be highlighted that the calculation of all these indices requires confidential data as input. Thus, a balance must be found between the necessary confidentiality of these data and the need for transparency that is required for CBA, as this is a necessary condition to obtain EU permitting and financial assistance.

Furthermore, monetisation of this market power index requires that the impact of a change in the market power index on socio-economic welfare is estimated. This requires that one is able to model the functioning of a future market under the hypothesis of imperfect competition, despite the fact that the validity of such a model is virtually impossible to prove. The inevitable model assumptions can radically change the results. Therefore, the results of a CBA, in terms of market power, can only be qualitative and its use as a reference for cost allocation would raise many objections.

A CBA study is typically performed by evaluating the impact of a project during its whole life-cycle. This requires a complete set of hypotheses on the future, such as the evolution of the level of consumption. Unfortunately, market power evolution cannot be modelled, as it is dependent on individual and regulatory decisions. Market structure could change dramatically in the future, for instance as the result of a merger. A solution to this issue could be to assess the impact of the infrastructure on the observed situation only. However, it should be noted that evaluating market power in a different hypothesis framework from the other aspects of the CBA would imply that the results are not consistent and should not be compared.

Building projects may have a positive impact on market power issues, but it is not the only solution.

The instability of market power, compared to the other aspects of a CBA, has a crucial impact on its relevance as part of a decision-making process. Dealing with generator ownership structures 10 or 20 years from now adds a highly uncertain dimension to the evaluation of European benefits of a given asset. Taking the impact of infrastructure capacity on market power into account in a CBA can strongly affect the identification of priority projects. Moreover, a change in the market structure can completely change the decision of building a particular project. This is all the more important considering that there are faster ways to solve market power issues, for example through regulation. By the time a project is completed, it is very likely that the market power issue has already been tackled by the regulator, and the project will not bring any benefit to this aspect. Therefore, taking market power into account in a CBA can lead to sub-optimal decisions.

The impact of future assets on current market power (which is generally positive) is an important indication, but this short-term aspect cannot be used in the assessment of an investment decision, which is, by definition, a long-term commitment.

6.24 Section 24: Multi-criteria analysis and cost benefit analysis

ENTSO-E favours a combined multi-criteria and cost benefit analysis that is well adapted to the proposed governance and allows an evaluation based on the most robust indicators, including monetary values if an opposable and coherent unit value exists on a European-wide level. This approach allows for a homogenous assessment of projects on all criteria.

ENTSO-E recognises that the primary goals of any project assessment method are:

- *Transparency*: the assessment method must provide transparency in its main assumptions, parameters, and values.
- *Completeness:* all relevant indicators (reflecting EU energy policy, as outlined by the criteria specified in annexes IV and V of the draft Regulation) should be included in the assessment framework.
- *Credibility/opposability*: if a criterion is weighted, the unit value must stem from an external and credible source (international or European reference).
- *Coherence*: if a criterion is weighted, the unit value must be coherent within the area under consideration (Europe or Regional Group).

As stated in the EC Guide to Cost-Benefit Analysis of Investment Projects, Economic appraisal tool for Cohesion Policy 2014-2020 (2014): 'In contrast to CBA, which focuses on a unique criterion (the maximisation of socio-economic welfare), multi-criteria analysis is a tool for dealing with a set of different objectives that cannot be aggregated through shadow prices and welfare weights, as in standard CBA.'

A fully monetised CBA alone cannot cover all criteria specified in Annexes IV and V of the Regulation (EU) No 347/2013, as some of these are difficult to monetise:

- This is the case for High Impact Low Probability events, such as 'disaster and climate resilience' (multiplying low probabilities and very high consequences have little meaning).
- Other benefits may have no opposable monetary value today.
- Some benefits have opposable values at a national level, but no common value exists in Europe. This is the case with, for instance, the Value of Lost Load (VOLL), which depends on the structure of consumption in each country (tertiary sector versus industry, importance of electricity in the economy, etc.).
- Some benefits (e.g., CO_2) are already partially internalised (e.g., in socio-economic welfare). Displaying a value in tons provides additional information.

6.25 Section 25: Value of Lost Load

Value of Lost Load (VOLL) is a measure of the costs for consumers associated with unserved energy (i.e., the energy that would have been supplied if there had been no outage), and is generally measured in €/kWh. It reflects the mean value of an outage per kWh (long interruptions) or kW (voltage dips, short interruptions), appropriately weighted to yield a composite value for the overall sector or nation considered. It is an externality, as there is presently no market for security of supply.

The value for VOLL that is used in project assessments should reflect the real cost of outages for system users, thereby, providing an accurate basis for investment decisions. A level of VOLL that is too high would lead to over-investment and a value that is too low would lead to under-investment. Under-investment would result in an inadequate security of supply because the costs of measures to prevent an outage are erroneously weighed against the value of preventing the outage. The optimal level should correspond to the consumer's willingness to pay for security of supply. Considering VOLL in project assessments requires that the right balance is struck between transmission reinforcements (which have a cost, reflected in tariffs) and outage costs. Transmission reinforcements generally contribute to improving the security and quality of the electricity supply, reduce the probability and severity of outages, and, thereby, reduce costs for consumers.

Experience has demonstrated that estimated values for VOLL vary significantly depending on geographic factors, differences in the nature of load composition, the type of consumers that are affected and their level of dependency on electricity, differences in reliability standards, the time of year, and the duration of the outage. Using a general and uniform estimation for VOLL would lead to inconsistency and less transparency and would greatly increase uncertainties compared to presenting the physical units. ENTSO-E does not intend to reduce the accuracy or level of information provided by its assessment results through the application of an estimated VOLL.

Providing a reliable figure for VOLL, which reflects the actual societal costs of an outage, is vital for a proper project assessment with a monetised expected energy not supplied (EENS)-component. When EENS is monetised, this is likely to shift the focus during interpretation of results away from the underlying values (i.e., a value in MWh that is different in each hour and in each price zone) because the monetised value is simply included in the summation of all monetised benefits and costs (e.g., to obtain a simple benefit-cost ratio). This is not problematic if an appropriate set of VOLL-values exists, which properly takes into account the spatial, temporal, and actual characteristics associated with the cost of EENS. However, if the values used for VOLL in different situations are based on disparate calculation methodologies, which is the case under the present state of knowledge regarding economic valuation of outages, the credibility of the otherwise uniform and standardised project assessment results is undermined. ENTSO-E, therefore, strongly discourages the use of the values reported in table 17, below, for project assessments and considers the availability of a computation methodology that is approved by ACER and the European Commission as a prerequisite for reporting monetised values of EENS.

The CEER has set out European guidelines[58] for nationwide studies on the estimation of costs due to electricity interruptions and voltage disturbances, recommending that '*National Regulatory Authorities should perform nationwide cost-estimation studies regarding electricity interruptions and voltage disturbances'*. Applying these guidelines throughout Europe would help to establish correct levels of VOLL, enabling comparable and consistent project assessments all over Europe. However, this is not yet the case, and an investigation program would be a pre-condition for adopting VOLL for consistent TYNDP or PCI assessments.

Note that in the absence of a uniform and standardised methodology to compute values for VOLL, EENS can nonetheless be monetised by stakeholders that make use of CBA results (e.g., the European Commission during the PCI process). The energy figure expressed in MWh, which ENTSO-E provides as the security of supply indicator in the CBA evaluation for each project, allows all interested parties to derive a monetised value by using the preferred VOLL available.

Table 17 provides an overview of VOLL values that are reported by different studies across Europe, as the result of an effort to monetise the VOLL. The overview shows widely varying values, ranging from as little as 0.20 €/kWh (Sweden, households) to more than 200 €/kWh (Austria, industry).

Table 17 provides an overview of values for VOLL in Europe, with an indication of the methodology used. The methodologies are not always properly documented; hence no direct comparison of values is possible. ENTSO-E does not endorse any of the values shown in Table 17.

[58] Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, CEER, December 2010. Other reports have also established such guidelines, such as CIGRE (2001) and EPRI References: (1) CIGRE Task Force 38.06.01: 'Methods to consider customer interruption costs in power system analysis'. Technical Brochure, August 2001; and (2) Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, CEER, December 2010.

Table 17: Overview of VOLL values (from different studies across Europe)

Country	VOLL (€/kWh)	Date	Used in planning?	Method/reference	Reference
Austria (E control)	WTP: Industry: 13.20 Households: 5.30 Direct worth: Households: 73.50 Industry : 203.93	2009	No	R&D for incentive regulation, Surveys using both WTP and Direct Worth	(4)
France (RTE)	Sectoral values for large industry, small industry, service sector, infrastructures, households & agriculture available: 26.00	2011	Yes (mean value)	CEER: surveys for transmission planning using both WTP, Direct Worth and case studies.	(12)
Great Britain	19.75	2012	No	Incentive regulation, initial value proposed by Ofgem	(13)
Ireland	Households: 68.00 Industry: 8.00 Mean: 40.00	2005	No	R&D, production function approach	(6)
Italy (AEEG)	Households: 10.80 (Business)[59]: 21.60 20.00-40.00 (according parameters)[60]	2003/ 2017	No	Surveys for incentive regulation, using both WTP and Direct Worth (SINTEF)	(3) & (5)
Netherlands (Tennet)	Households: 16,40 Industry: 6,00 Mean: 8,60	2003	No	R&D, production function approach	(7)
Norway (NVE)	Industry: 10.40 Service sector: 15.40 Agriculture: 2.20 Public sector: 2.00 Large industry: 2.10	2008	Yes (sectorial values)	Surveys for incentive regulation, using both WTP and Direct Worth (SINTEF)	(9), (10)
Portugal (ERSE)	1.50	2011	Yes (mean value)	Portuguese Tariff Code	(14)
Spain	6.35	2008	No	R&D, production function approach	(8)
Sweden	Households: 0.20 Agriculture: 0.90 Public sector: 26.60 Service sector: 19.80 Industry: 7.10	2006	No	R&D, WTP, conjoint analysis	(11)

References:

1) CIGRE Task Force 38.06.01: 'Methods to consider customer interruption costs in power system analysis'. Technical Brochure, August 2001.

2) CEER, 'Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances', December 2010.

[59] The value for Transmission could rise to 40€/kWh (5th CEER Benchmarking Report on the Quality of Electricity Supply, 2011)

[60] National Network Code Annex 74 and Attachment to the National Development Plan (page 76)

3) A. Bertazzi and L. Lo Schiavo, ‘The use of customer outage cost surveys in policy decision-making: the italian experience in regulating quality of electricity supply’.

4) Markus Bliem, ‘Economic Valuation of Electrical Service Reliability in Austria – A Choice Experiment Approach’, IHSK, 2009.

5) CEER, ‘5th CEER Benchmarking Report on the Quality of Electricity Supply‘, 2011.

6) Sustainable Energy Ireland, ‘Security of Supply in Ireland’, 2007.

7) Nooij, Koopmans and Bijvoet, ‘The value of security of supply’, SEO, 2005.

8) Pedro Linares and Luis Rey, ‘The costs of electricity interruptions in Spain. Are we sending the right signals?’, Alcoa Foundation, 2012.

9) FASIT, KILE-satser, 2011.

10) G. Kjölle, ‘Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results’ (SINTEF), IEEE TRANSACTIONS ON POWER SYSTEMS, 2008.

11) F. Carlsson, and P. Martinsson, ‘Kostnader av elavbrott: En studie av svenska elkunder’, Elforsk rapport nr 06:15, (2006).

12) RTE, ‘Quelle valeur attribuer à la qualité de l’électricité ?’, 2011.

13) Reckon, ‘Desktop review and analysis of information on Value of Lost Load for RIIO-ED1 and associated work’, May 2012

14) ERSE, ‘PARÂMETROS DE REGULAÇÃO PARA O PERÍODO 2012 A 2014’, Dezembro 2011.

End note.

System development tools are continuingly evolving, and it is the intention that this document will be reviewed periodically pursuant to Regulation (EU) n.347/2013, Art.11 §6 and in line with prudent planning practices and further editions of the ENTSO-E’s TYNDP document.

6.26 Section 26: Project level assessment based on promoters' input

This 3rd CBA guideline introduces project level indicators. Project level indicators are designed to address the instances where it is not possible for ENTSO-E to assess certain benefits at a pan-European level within the TYNDP process.

The project level benefits that are identified are as follows:

- B7.1: Balancing Energy Exchange
- B8.1: Frequency Stability
- B8.2: Blackstart services
- B9: Avoidance of the renewal/replacement costs of infrastructure
- B10: Reduction of necessary reserve for re-dispatch power plants

The other indicators presented in this guideline, which have not been listed above or are not computed applying a redispatch methodology[61], are not treated as project level indicators.

The detailed assessment requirements for the indicators are described in the TYNDP project sheets and are addressed in the corresponding support sections that are dedicated to each indicator.

Implementation details for the assessment of these benefits are also described in the implementation guidelines that are also provided.

In order for the indicators to be accepted in the TYNDP project sheets, project promoters should provide the following justification elements:

1) **Information on the study performed to assess the project level benefit:**

    a. Title of the study;

    b. Year of the study;

    c. Name of the company that has performed the study; and

    d. A link or copy of the study should be made available according the terms of the TYNDP process.

2) **The study shall contain the following information:**

[61] Redispatch calculations are currently assumed at a project level.

a. The assumptions made, together with a detailed explanation. The assumptions required for each project level benefit are detailed in the supporting section that is dedicated to that benefit;

b. Data source (if requested, the promoter should also be able to provide the data-set that was used);

c. Details of the tool(s) used to compute the benefit;

d. Clear explanation of how the methodology illustrated in this guideline has been implemented and applied to perform the study; and

e. Clear demonstration that the figures provided in the study relate to countries within the ENTSO-E perimeter only.

Annexes

I. Generation cost approach

The economic benefit is calculated from the reduction in total generation costs associated with the NTC variation created by the project. There are three aspects to this benefit:

a. By reducing network bottlenecks that restrict the access of generation to the full European market, a project can reduce the costs of generation restrictions, both within and between bidding areas.

b. A project can contribute to reduced costs by providing a direct system connection to new, relatively low cost, generation. In the case of connection of renewables, this is also expressed by benefit B3, RES Integration.

c. A project can also facilitate increased competition between generators, reducing the price of electricity to final consumers. The methods do not consider market power (see Section 23: Impact on market), and as a result the expression of socio-economic welfare is the reduction in generation costs.

An economic optimisation is undertaken to determine the optimal dispatch cost of generation, with and without the project. The benefit for each case is calculated from the following relationship:

Benefit (for each time step) = Generation costs without the project (sum over all time steps) – Generation costs with the project (sum over all time steps)

The socio-economic welfare, in terms of savings in total generation costs, can be calculated for internal constraints by redispatch (see Chapter 2.3 Cross-border versus internal). In any case, the method used for the SEW calculation must be clearly highlighted.

The total benefit for the horizon is calculated by summarising the benefit for all the hours of the year, which is done through market studies.

II. Total surplus approach

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 sum of the producer surplus (difference between electricity price and generation cost), the consumer surplus (difference between willingness-to-pay the value of electricity and electricity price for a demand block), and the change in congestion rent (difference in electricity prices between price zones), with and without the project.

Total surplus = Producer Surplus + Consumer Surplus + Congestion Rents

The economic benefit is calculated by adding the producer surplus (a measure of producer welfare), the consumer surplus (a measure of consumer welfare), and the congestion rents for all price areas, as shown in Figure 12. The total surplus approach consists of the following three items:

a. By reducing network bottlenecks, the total generation cost will be economically optimised. This is reflected in the sum of the producer surpluses that are defined as the difference between the prices the producers are willing to supply electricity and the generation costs.

b. By reducing network bottlenecks that restrict the access of import from low-price areas, the total consumption cost will be decreased. This is reflected in the sum of the consumer surpluses that are defined as the difference between the prices the consumers are willing to pay for electricity and the market price.

c. Reducing network bottlenecks will lead to a change in total congestion rent for the TSOs.

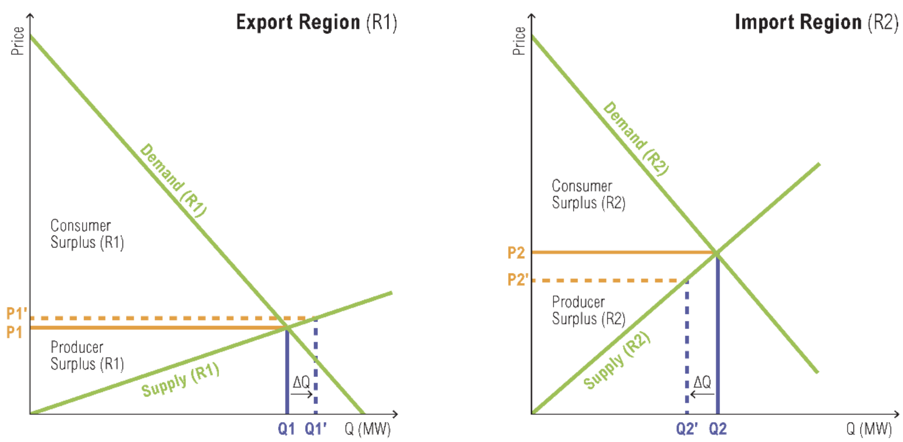


Figure 12: Example of a new project that increases transfer capacity (ΔQ) between an export and an import region.

A project with a NTC variation between two bidding areas with a price difference will allow generators in the low price bidding area to supply load in the high price bidding area. In a perfect market, the market price is determined at the intersection of the demand and supply curves.

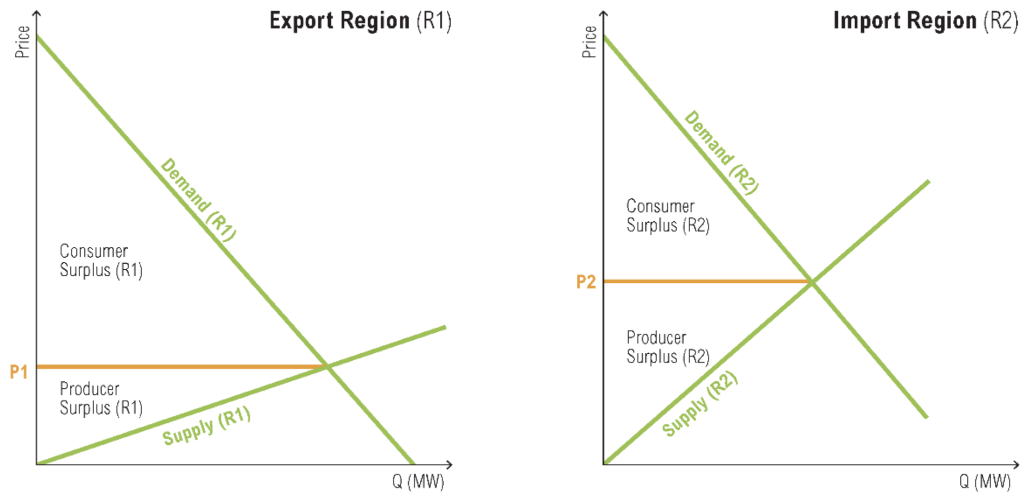


Figure 13: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity (elastic demand)

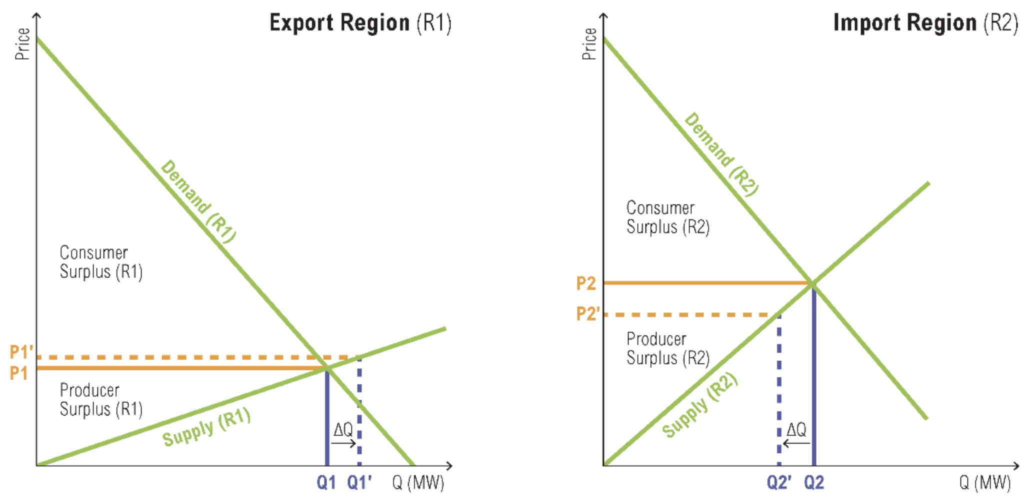


Figure 14: Example of an export region and an import region, with a new project increasing the GTC between the two regions (elastic demand)

A new project will change the price of both bidding areas. This will lead to a change in consumer and producer surplus in both the export and import areas. Furthermore, the TSO revenues will reflect the change in total congestion rents on all links between the export and import areas. The benefit of the project can be measured through the change in socio-economic welfare. The change in welfare is calculated by:

Change in welfare = change in consumer surplus + change in producer surplus + change in total congestion rents

The total benefit for the horizon is calculated by summing the benefit for all time steps considered in that year.

The total surplus is maximised when the market price is at the intersection of the demand and supply curves.

Inelasticity of demand

In the case of the electricity market, short-term demand can be considered as inelastic, as customers do not respond directly to real-time market prices (no willingness-to-pay-value is available). The change in consumer surplus[62] can be calculated as follows:

For inelastic demand: change in consumer surplus = change in prices multiplied by demand

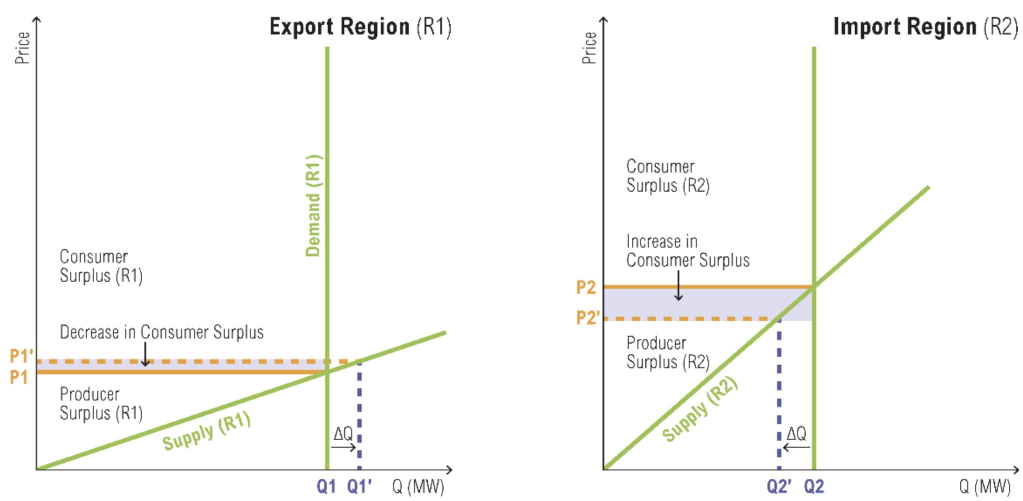


Figure 15: Change in consumer surplus

The change in producer surplus can be calculated as follows:

Change in producer surplus = change in generation revenues[63] – change in marginal generation costs

[62] When demand is considered as inelastic, the consumer surplus cannot be calculated in an absolute way (it is infinite). However, the variation in consumer surplus, as a result of the new project, can be calculated nonetheless. It equals the sum for every hour of the year of: (marginal cost of the area x total consumption of the area)$_{\text{with the project}}$ – marginal cost of the area x total consumption of the area)$_{\text{without the project}}$

[63] Generation revenues equal: (marginal cost of the area x total production of the area).

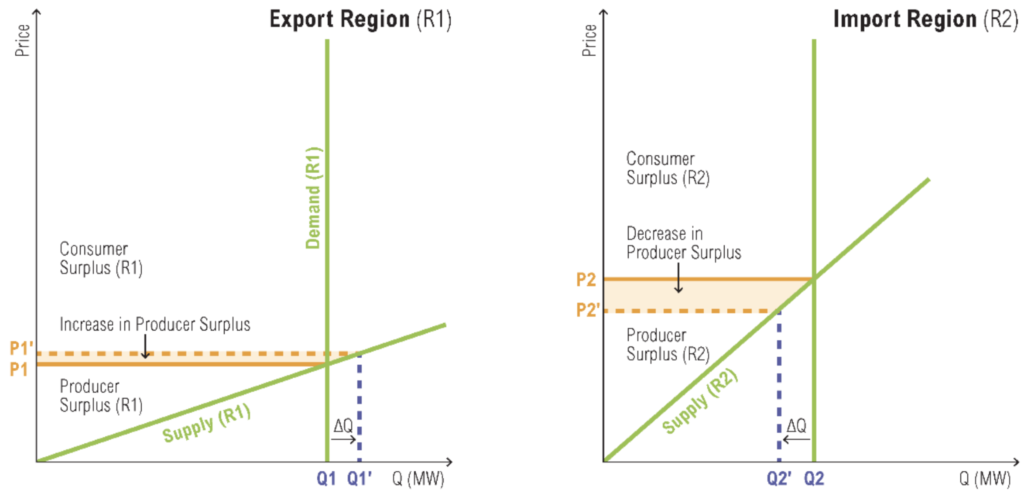


Figure 16: Change in producer surplus

The congestion rents with the project can be calculated from the price difference between the importing and the exporting areas, multiplied by the additional power traded by the new link[64].

The change in total congestion rent can be calculated as follows:

Change in total congestion rent = change of congestion rents on all links between import and export areas

The benefit for each case is calculated by:

Benefit (for each time step) = Total surplus with the project (sum over all time steps) – Total surplus without the project (sum over all time steps)

The total benefit for the horizon is calculated by summarising the benefit for all the hours of the year, which is done through market studies.

[64] In a practical way, it is calculated as the absolute value of (Marginal cost of Export Area – Marginal cost of Import Area) x flows on the interconnector.