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

Draft version

15 October 2019

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 of taking into account stakeholder suggestions over a 5 years development process. During this period, it was also consulted with Member States and National Regulators and 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 ENTSO-E to draft 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 detail in the assessment guideline. ENTSO-E aims with this approach to develop a CBA guideline that can be used not only for one TYNDP but rather to include strong principles that would stand for a longer time. The 2nd CBA guideline has been used by ENTSO-E to assess projects benefits in the TYNDP 2018. However, although improvements were included in the 2nd CBA guideline, still some so called 'missing benefits' where added to the TYNDP 2018 on top of what is defined in the 2nd CBA guideline. This together with the constant effort of ENTSO-E to improve the CBA guideline caused 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 of new indicators. Among these, some new indicators stem from the lessons learnt from the "Missing Benefits" process established for TYNDP 2018; however, the complexity of some of this new indicator does not allow to perform a Pan-European assessment. For this reason, the 3rd CBA guideline includes new "Project level indicators" whose nature will be clarified in Chapter 3.5.

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.

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1 Introduction and scope

This Cost Benefit Analysis of Grid Development Projects guideline is developed in compliance with the requirements of the EU Regulation (EU) 347/2013. The objective of the Regulation is to ensure a common framework for multi-criteria cost-benefit analysis (CBA) for ENTSO-E Ten Year Network Development Plan (TYNDP) projects.

From the list of TYNDP projects, candidate projects Projects of common Common interest Interest (PCI) are identified. This guideline is also recommended to be used for the cross border cost allocation (CBCA) process as the standard guideline for the project-specific CBAs required by Regulation (EU) 347/2013 Article 12(a).

The uniform application of this guideline means that all projects (including storage and transmission projects) and promoters (either TSO or third party) are treated and assessed in the same way.

A number of indicators have been developed to support the specific requirements given in Article 4.2 of the Regulation in respect of market integration; sustainability (including the integration of renewable energy into the grid, energy storage, etc.) and security of supply. This is reflected in the structure of the main categories of the project assessment methodology described in this CBA guideline below.

The indicators defined in this CBA guideline are designed to be evaluated in compliance with the stipulations of the Regulation 347/2013 (Article 11, Annex IV and Annex V)..

This guideline may also be of use to anyone seeking to assess transmission investments as it provides a comprehensive and rigorous structure within which to undertake a cost benefit analysis.

1.1 Transmission system planning

The move to a more diverse power generation portfolio due to the rapid development of renewable energy sources (RES) and the liberalisation of the European electricity market has resulted in increasingly interdependent power flows across Europe, with large and correlated variations. Therefore, transmission system design must look beyond traditional (often national) Transmission System Operators' (TSOs) boundaries and progress towards regional and European solutions. Close cooperation of ENTSO-E member companies, which are responsible for the future development of the European transmission system, is vital to achieve coherent and coordinated planning that is necessary for such solutions to materialise.

The main objective of transmission system planning is to ensure the development of an adequate pan-European transmission system which:

- Enables safe grid operation;
- Enables a high level of security of supply;
- Contributes to a sustainable energy supply;
- Facilitates grid access to all market participants;

- Contributes to internal market integration, facilitates competition, and harmonisation;
- Contributes to energy efficiency of the system; and
- Enables cross-country power exchanges.

In this process certain key rules have to be kept in mind, in particular:

- Requirements and general regulations of the liberalised European power and electricity market set by relevant European Union (EU) legislation;
- EU policies and targets;
- National legislation and regulatory framework;
- Security of people and infrastructure;
- Environmental policies and constraints;
- Transparency in procedures applied; and
- Economic efficiency.

The planning criteria used to govern the design of transmission systems are generally specified in transmission planning documents. Such criteria have been developed for application by individual TSOs taking into account the above mentioned factors, as well as specific conditions of the network to which they relate. Within the framework of the pan-European TYNDP, ENTSO-E has developed common Guidelines for Grid Development (e.g. Annex 3 of TYNDP 2012). Thus, suitable methodologies have been adopted for future development projects and common assessments have been developed.

Furthermore, Regulation (EU) 347/2013 (also referred to as 'the Regulation') requests ENTSO-E to establish a "methodology, including on network and market modelling, for a harmonised energy system-wide cost-benefit analysis at Union-wide level for projects of common interest" (Article 11).

1.2 Scope of the document

The 3rd CBA guideline describes the common principles and procedures for performing combined multi-criteria and cost-benefit analysis using network, market and interlinked modelling methodologies (Chapter 2.2) for developing Regional Investment Plans and the Union-wide TYNDP, in accordance with Regulation (EU) 714/2009 of the 3rd Legislative Package. Following Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure, it also serves as a basis for a harmonised assessment of PCIs at the European Union level.

When planning the future power system, new transmission assets are one of several possible system solutions. Other possible solutions include energy storage, generation, and demand-side response (DSR). Storage projects are therefore, in principle, assessed in a similar way as transmission projects even though their benefits sometimes lay more on the side of ancillary services, which are vital to the system, than on the classical CBA indicators. This is described in this CBA guideline in Chapter 4: Assessment of storage.

This 3rd CBA guideline sets out the ENTSO-E criteria for the assessment of costs and benefits of a transmission (or storage) project, all which stem from European policies on market integration, security of supply and sustainability. In order to ensure a full assessment of all transmission benefits, some of the indicators are monetised, while others are quantified in their typical physical units (such as tonnes or GWh). A general overview of the indicators is given in Chapter 3.3, while a more detailed representation of each category is given in Chapters 3.4, 3.6 and 3.7. This set of common indicators forms 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].

An overview of the process is given in Figure 1: Overview of the assessment process inside the TYNDP and for identifying PCIs

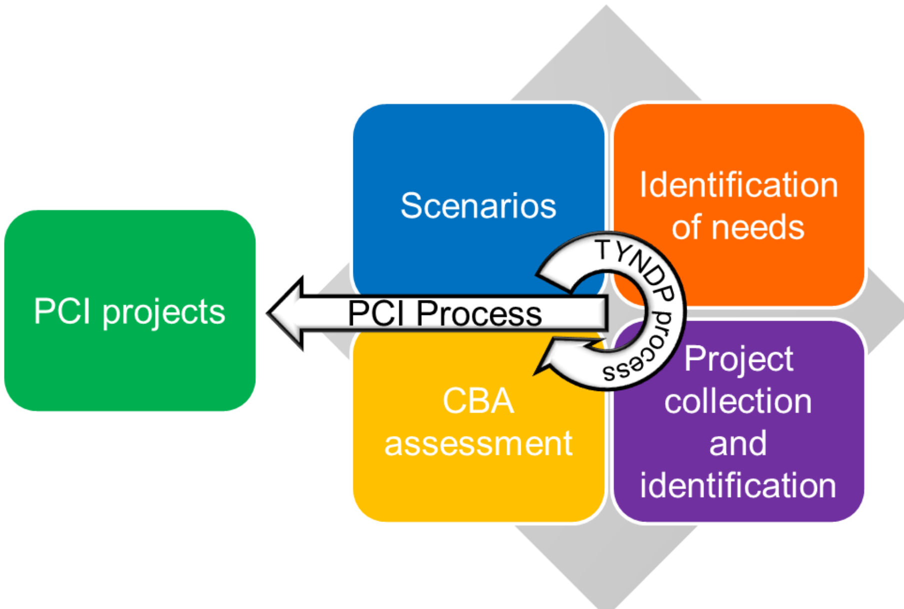

Figure 1: Overview of the assessment process inside the TYNDP and for identifying PCIs

1.3 Content 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 a project promoter(s) defining a project that addresses this need. Following Regulation (EU) 347/2013, these projects must be assessed under different planning scenarios, each of which represents a possible future development of the energy system.

[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 »

The aim of this document is to deliver a general guideline on how to assess these reinforcements from a cost and benefit point of view. Whilst their costs mostly depend on scenario independent factors like routeing, technology, material, etc., benefits strongly correlate with scenario specific assumptions. Therefore, scenarios which define potential future developments of the energy system are used to gain an insight in the future benefits of transmission projects. The essence of scenario analysis is to come up with plausible pictures of the future. The assessment process takes place primarily in the context of TYNDP development according to the methodology that is described in this document. Although the scenarios are developed in the context of the biennial TYNDP cycle, a short overview of the scenario development process together with the modelling framework is provided in Chapter 3.5 of this 3rd CBA guideline.

A detailed description of the overall assessment, including the modelling assumptions and indicator structure, is given in Chapter 3.

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

The CBA guideline is developed to evaluate the benefits and costs of TYNDP projects from a pan-European perspective, providing important input for the selection process of PCIs. In this context the main objective of the 3rd CBA guideline is to provide a common and uniform basis for the assessment of projects regarding their value for European society.

The cost-benefit impact assessment criteria adopted in this document reflect each project's added value for society. Hence, economic and social viability are displayed in terms of increased capacity for trading of energy and balancing services between bidding areas (market integration), sustainability (RES integration, CO_2 variation) and security of supply (secure system operation). The indicators also reflect the effects of the project in terms of costs and environmental viability. They are calculated through an iteration of market and network studies. It should be noted that some benefits are partly, or fully, internalised within other benefits such as avoided CO_2 and RES integration via socio-economic welfare, while others remain completely non-monetised.

This is a continuously evolving process, so 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 EU Regulation 347/2013).

2 General Approach

The general approach to the assessment of projects takes into account the range of future energy scenarios; a definition of the reference network used to assess the impact of the reinforcement; and the acceptable techniques to be used in undertaking the analysis. The scenarios reflect European and national legislations in force at the time of the analysis and consider plausible energy futures characterised by, amongst others, **generation portfolios**, **demand forecasts** and **exchange patterns** with the systems outside the study region etc. The range of simulations to be undertaken spans market simulations;

network simulations and re-dispatch simulations. Project benefits are then calculated as the difference between simulations including the project and simulations exclude the project. Consequently, the reference case has a significant impact on the outcome of an individual project assessment. Each of these general topics is discussed in detail below.

2.1 Scenarios and Study Horizons

Scenarios are constructed at the level of the European electricity system and can be adapted in more detail at a regional level. They reflect European and national 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 characterised by, amongst others, **generation portfolio**, **demand forecast** and **exchange patterns** with the systems outside the study region, etc. The scenarios are a representation of what the generation-transmission-consumption system could look like in the future and a means of addressing future uncertainties and the interaction between these uncertainties. The objective is to construct contrasting future developments that differ enough from each other to capture a realistic 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 the further calculation of the grid development needs. All projects included in the TYNDP must be assessed against the same set of scenarios (provided that the project is assessed for a given reference year).

Multi-criteria cost-benefit analysis of candidate projects of European interest are based on the scenarios developed in ENTSO-E's TYNDP. These visions provide the framework within which the future is likely to occur but does not attach a probability of occurrence to them. Some TYNDP visions have a stronger national focus than others; some are 'top-down'; others are 'bottom-up' etc. There is no right or wrong; likely or unlikely option: all visions have to be treated equally and, due to 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 the power balance, margins, energy indicators and generation mix. The scenarios are elaborated after formally consulting Member States and the organisations representing all relevant stakeholders.

Scenarios can be distinguished depending on the time horizon (see also Figure 2):

- 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 techniques.

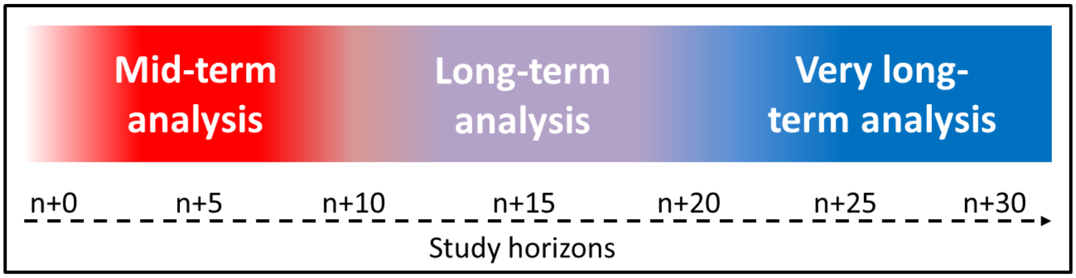

Figure 2: Time horizons: continuous timeline with future study years and corresponding study horizons: mid-term (red), long-term (purple) and very long-term (blue)[2]

As shown in Figure 2, the scenarios developed in a long-term perspective may be used as a bridge between mid-term horizons and very long-term horizons (n+20 to n+40). The aim of the perspectives beyond n+20 should be that the pathway realised in the future falls within the range described by the scenarios within reasonably possible expectations.

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

2.2 Cross-Border versus Internal Projects

Assessing projects by just focusing on the impact of transfer capacities across certain international borders can lead to an underestimation of the project specific benefits 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 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 by market simulations considering one node per country, if not using a flow based model.

Both internal and cross-border projects can be of pan-European relevance according to the CBA. They however all develop grid transfer capability (GTC) over a certain boundary, which may or not be an international border (and sometimes several boundaries).

[2] 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.

For different types of projects, different methods should be used, as there is no unified method yet available that could handle the special aspects of all these projects in a satisfying way. Therefore, three options are given to calculate the benefits (for more details also see Chapter 2.3):

- market simulations;
- network simulations;
- combined market and network simulations, i.e. redispatch simulations.

As not all indicators can be calculated using all methodologies, for each indicator the respective possible methodology will be given in a dedicated Section.

2.3 Modelling framework

Market simulations

Market studies are used to calculate the cost optimal dispatch of generation units under the constraint that the demand for electricity is fulfilled (taking into account DSR) in each bidding area and in every modelled time step[3]. Besides the dispatch of generation and demand (if modelled endogenously), market simulations compute the market exchanges between bidding areas and corresponding marginal costs for every time step. Market studies are used to determine the benefits of providing additional transport capacity and enabling a more efficient usage of generation units available in different locations across bidding areas. They take into account several constraints such as flexibility and availability of thermal units, hydro conditions, wind and solar profiles, load profile and outages. They also allow the measurement of savings in generation costs due to the investments in the grid (and/or in storage).

Market studies results allow the computation of some of the CBA indicators, such as socio-economic welfare (SEW), CO_2 and non-CO_2 emissions, RES integration and the adequacy and flexibility component of security of supply. The output of market simulations will be used as an input for defining the generation, consumption and power flows in the grid, allowing load flow calculations to be performed.

There are different options to represent the transmission network in market models, namely:

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

  Using a simplified (NTC) model of the physical grid, the bidding areas are represented as a network of interconnected nodes connected by a transport capacity that is available for market exchanges (NTC). These NTC values represent an approximation of the potential for market exchanges using the physical (direct or indirect[4]) interconnections that exist between each pair of

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

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

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, which consider the interrelation between the power-flow as obtained from network simulations and the corresponding potential for market exchanges, and vice versa. Flow-based market simulations take into account the relationships between each potential market exchange and its corresponding utilization of the physical grid capacities (cross-border as well as internal grid). Flow-based market simulations thus use (a representation of) the physical grid capacities to define the constraints for market exchanges rather than a set of independent NTC values.

Network simulations

Network studies represent the transmission network in a high level of detail and are used to calculate the actual load flows that take place in the network under given generation/load/market exchange conditions. Network studies allow bottlenecks in the grid corresponding to the power flows resulting from the market exchanges to be identified.

Network studies results allow the computation of some indicators such as: ΔNTC and variation of grid losses.

Both types of studies – market and network – thus provide different information. They generally complement one another and are therefore often used in an iterative manner.

Redispatch simulations

Redispatch simulations can be seen as a combination of both network and market studies by combining network contingencies with the economy of the generation dispatch. These redispatch simulations compute the costs of alleviating overloads (taken from network simulations) by adjusting the initial dispatch (taken from market simulations) while maintaining the same power plant specific constraints that were also applied for the market simulations such as minimum up- and down times, ramp rates, must-run obligations, variable costs, etc.

Redispatch simulations assist in the computation of the CBA indicators (the same as for market simulations) when it concerns the evaluation of projects using the initial generation dispatch from NTC-based market simulations as a starting point. A detailed description of redispatch simulations within the CBA frame is given in Section 21: Redispatch simulations for project assessment.

2.4 Baseline/reference network

The reference grid is the grid that is made up of the existing grid and the projects that have a strong chance of being implemented by the date of the scenarios that are considered. It is used as the starting point of the CBA.

Market and network simulations with projects either added to the reference grid, or removed from it, are compared to the simulations of the reference grid alone to assess each of the projects' performance. Two methods for project assessment made use of are described as follows:

- **Take Out One at the Time (TOOT) method**, where the reference case reflects a future target grid situation in which all additional network capacity is presumed to be realised (compared to the starting situation) and projects under assessment are removed from the forecasted network structure (one at a time) to evaluate the changes to the load flow and other indicators.
- **Put IN one at the Time (PINT) method**, where the reference case reflects an initial state of the grid without the projects under assessment, and projects under assessment are added to this reference case (one at a time) to evaluate the changes to the load flow and other indicators.

The selection of projects that comprise the reference grid has a strong impact on overall CBA results. As a result, a clear explanation of which projects are included should be given. This should include an explanation of the initial state of the grid (i.e. the existing grid as defined in the year of the study).

Furthermore, 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 is included in the reference grid. This can be assessed by considering the development status of the project. The reference grid is then built up by including the most mature projects that are either: a) in the construction phase; or, b) in the 'permitting' or 'planned, but not yet permitting' phase where their timely realisation is most likely (e.g. when the country specific legal requirements have stated the need of the projects to being realised).

The second maturity requirement -b- (to be applied to 'permitting' and 'planned, but not permitting' stages) can be strengthened by verifying the position of the project with respect to further criteria, provided that an uniform and consistent application throughout the perimeter of the study is feasible. These further criteria may be:

- 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 stat ed 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 documental reference to the environmental impact assessment;
- There is a documental reference to the request for permits;
- Clearly defined system needs - 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.

If the study involves countries with different procedures in the permitting process, it might be recommendable to apply expert's judgement, supported by studies focused on a conservative forecast of the future grid as Mid-Term Adequacy forecasts. Projects in the 'under consideration' phase are seen as non-mature and have therefore generally to be excluded from the reference grid leading to an assessment using the PINT approach, regardless of their position with respect to the additional criteria mentioned.

To obtain the NTC value of the reference network, the NTC increases of each single (non-competing) project has to be taken into account. As different scenarios with different assumptions might have different expected capacities, this also has to be reflected by the reference network, i.e. it has to be clearly explained that the reference network reflects the assumptions made by the scenarios. It should also be taken into account that in several cases, the calculated NTC increases (from the previous TYNDP, if the project was already included) cannot simply be added to the present NTC values, but expert estimations are needed to correctly take into account the increases when determining the NTCs for the reference grid.

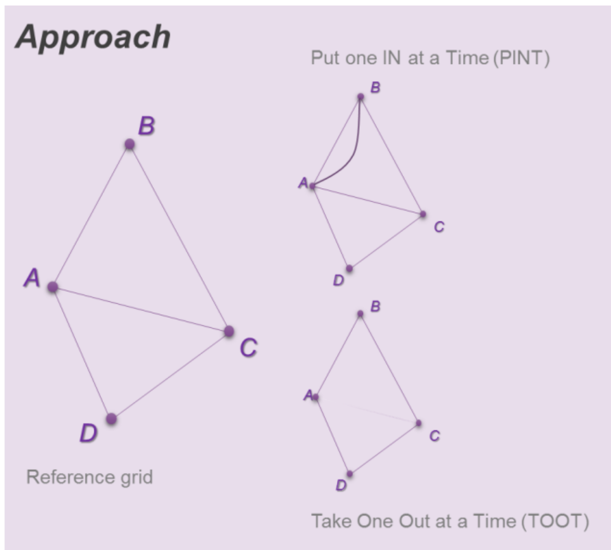

Figure 3: Illustration of TOOT and PINT approaches

The TOOT and PINT methods are to be applied consistently for both market and network simulations. For the latter method, the reference network is clearly defined by the network model that is used; and 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 (e.g. when using the TOOT approach, each project under assessment has to be added to the grid model and its contribution to commercial capacity has to be added to the respective boundaries).

The TOOT method provides an estimation of benefits for each project, as if it were the last to be commissioned. In fact, the TOOT method evaluates each new development project into the whole forecasted network. The advantage of this analysis is that it immediately appreciates every benefit brought by each project, without considering the order of projects. All benefits are considered in a conservative manner, in fact each evaluated project is considered into an already developed environment, in which all programmed development projects are present. Hence, this method allows analyses and assessments at TYNDP level, considering the whole future system environment and every future network evolution.

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 underestimates the benefits of projects because all project benefits are calculated under the assumption that the project is the last (marginal) project to be realised. On the other hand, the application of the PINT approach overestimates the benefit of projects (compared to all other PINT projects) because all 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 gets built, a second one will have lower benefits). This effect is generally the 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.

For interdependent projects, the strict application of TOOT/PINT may not fully reflect the benefits of the projects. Therefore, in addition to the project benefits as calculated under the strict application of TOOT/PINT, the benefits can be calculated in relation to the realisation of other projects on the same boundary (multiple TOOT/PINT) and additionally present these results in the respective study. When the multiple TOOT/PINT method or a combination of both is applied, a detailed description of the sequence of projects must be given.

2.5 Multi-case analysis

System planning studies are carried out with market simulations producing results for each time step (typically one hour). The network studies then perform load flow calculations using these results for each time step.

In order to simplify the volume of network calculations, network studies may group results from several time steps into one planning case. This can only be done where 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, and exchange profiles, and especially on the availability profiles for variable renewable energy sources.

2.6 Sensitivities

Sensitivity analysis can be performed with the intention of observing how certain changes of scenario (e.g. by changing only one parameter or a set of interlinked parameters) affects the model results in order to achieve a deeper understanding of the system's behaviour regarding these 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 and it is therefore 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 be optionally be used to perform sensitivity studies. This list is not exhaustive and provides some examples of useful sensitivities within the boundaries of the storyline of the scenarios.

- **Fuel and CO_2-Price**

  Within the scenario development process, a global set of values for fuel prices is defined. Nevertheless, a certain degree of uncertainty for 2030 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 to see the impact of merit order shifts to CBA-results is a valuable sensitivity.

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

  Because the cost of CO_2 as included in the generation costs (B1) may understate (or overstate) the full long-term societal value of avoiding CO_2, a sensitivity analysis could be performed for this indicator, under which CO_2 is valued at a long-term societal price. To perform this sensitivity without double-counting against B1:

  a. Derive the delta volume of CO_2, as above;
  b. Consider the CO_2 price internalised in B1;
  c. Adopt a long-term societal price of CO_2.

  Multiply the volume of a) by the difference in prices c) minus b). This represents the monetisation of this sensitivity of an increased value of CO_2.

  For this sensitivity there is no adjustment in the merit order and the dispatch for B1 for the higher carbon price. If such exercise is to be performed, that would represent a full re-run of the indicator B1, against the different data assumption of a higher forecast carbon price included in the generation background and merit order.

- **Climate year**

  Using historic climate data of different years might influence the benefits of a project. For example, the indicator RES-integration depends on the infeed of RES and thus on 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 in order to see how the indicators evolve under particular climate conditions.

- **Load**

Regarding the development of load, two opposed drivers can be identified. On the one hand energy efficiency will lead to decreasing load; and on the other hand, more and more applications will be electrified (e.g. e-mobility, heat pumps etc.), which will lead to an increasing load. Sensitivity analysis of load could be conducted by varying the peak load and/or the annual energy that is needed.

- **Technology phase-out**

  Due to external circumstances, a phase-out 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.

- **Must-run**

  If thermal power plants provide not only electrical power but also 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 least 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**

  For each scenario, the storyline defines the volume of installed RES capacity. However, sensitivity on the RES installed capacity could be performed to give hint on the impact of the delay or the ahead schedule of RES arrival.

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

The goal of project assessment is to characterise the impact of transmission projects, both in terms of added value for society (increase of capacity for trading of energy and balancing services between bidding areas, RES integration, increased security of supply), as well as in terms of costs.

It is the task of ENTSO-E to define a robust and consistent methodology to assess the contribution of projects across Europe on a consistent basis. ENTSO-E developed 3rd CBA guideline to achieve a uniform assessment process for transmission projects across Europe.

A robust assessment of transmission projects, especially in a meshed system, is a complex matter. Additional transmission infrastructure provides more transmission capacity and hence allows for an optimization of the generation portfolio, which leads to an increase of SEW throughout Europe. Further benefits such as Security of Supply (SoS) or improvements of the flexibility and stability also have to be taken into due account.

The assessment of costs and benefits are undertaken using combined cost-benefit and multi-criteria approach within which both qualitative assessments and quantified, monetised assessments are included.

In such a way the full range of costs and benefits can be represented, highlighting the characteristics of a project and providing sufficient information to decision makers.

Such an approach recognises that a fully monetized 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. Multi-criteria analysis however can account for each of these including the compilation of a cost-benefit analysis of those elements that can be monetized, while recognising that other elements also exist that are not quantified.

This chapter establishes a methodology for the clustering of investments into projects[5]; defines each of the cost and benefit indicators; and the project assessment required for each indicator.

3.1 Multi-criteria assessment

The overall assessment is displayed as a combined cost-benefit and multi-criteria matrix in the TYNDP, as shown in Chapter 3.3: most indicators are quantified; e.g. costs, SEW, SoS Adequacy and the variation of transmission losses are displayed in Euros. The other indicators are displayed using the most relevant units ensuring both a coherent measure across Europe and an opposable value, while avoiding the double accounting in Euros.

Using this combined cost-benefit and multi-criteria assessment each project is characterised by its impact of both the added value for society and in terms of costs in a standardised way. Therefore, the overall impacts, positive as well as negative, for each project can be compared. The overall combined cost-benefit and multi-criteria assessment of transmission projects, especially in a meshed system, is a complex matter and highlights the characteristics of a project and gives sufficient information to the decision-makers. Only by considering all of the indicators can the total benefit of a project be described, while the importance of each indicator might be project specific: the main aim of one project might be to significantly integrate large amounts of RES into the grid, while for another the focus may lies more on increasing 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 the only ones.

The following figure displays a simplified overview of the whole process of project assessment resulting in the set of CBA indicators.

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

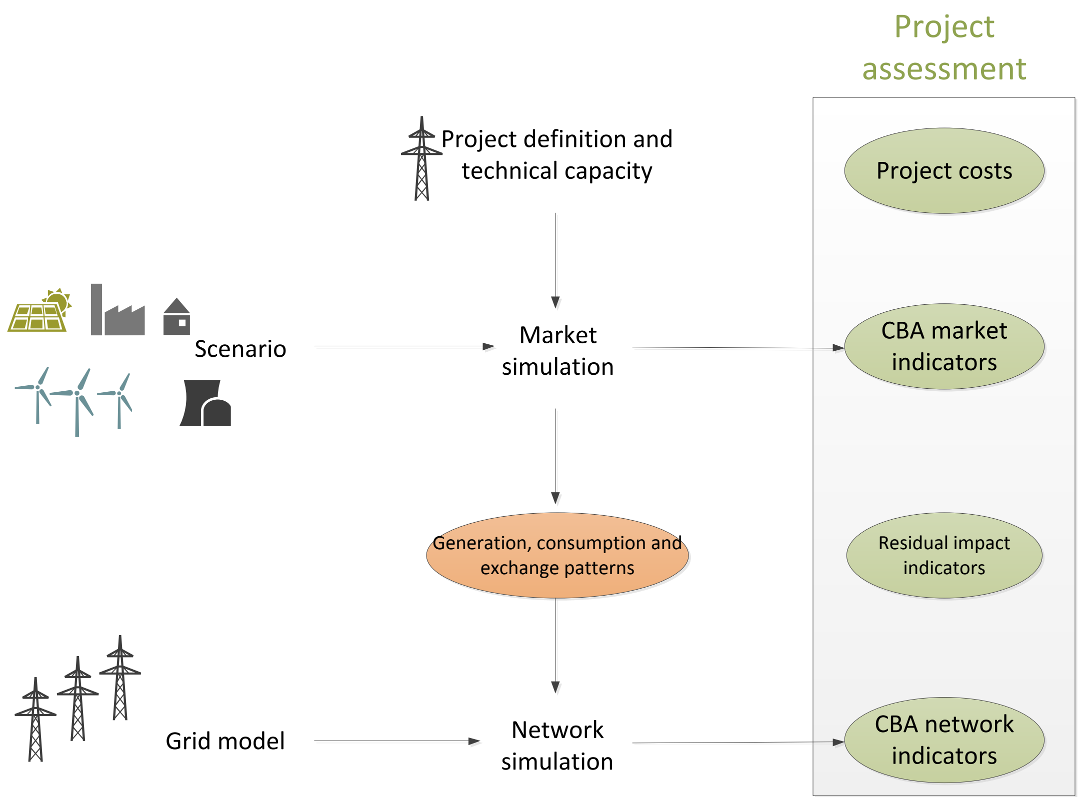

Figure 4: Schematic project assessment process. While "CBA market indicators" and "CBA network indicators" are the direct outcome of market and network studies[6], respectively, "project costs" (see 6.14 and 6.15) and "residual impacts" (see 6.17, 6.18 and 6.19) are obtained without the use of simulations

3.2 General assumptions

This sub-chapter provides the general guidance necessary to assess projects beyond the calculation of the individual indicators. It provides guidelines for clustering; computation of transfer capability (i.e. in meshed networks the physical capacity of the investment is usually different from is capability to accommodate a market transfer); the geographic scope to take into consideration; and, the calculation of a net-present value on the basis of the (monetized) indicators that are available for the project.

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

3.2.1 Clustering of investments

In some cases, it may be necessary to realize a group of investments together in order to develop transmission capacity (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. Project assessment is done for the combined set of clustered investments.

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 realization of the full potential of another (main) investment. Investments which contribute only marginally to the full potential of the main investment are not allowed to be clustered together.

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

- If an investment is significantly delayed[7] compared to the previous TYNDP, it can no longer be clustered within this project. In order to avoid that 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 realized eventually), a limiting criterion is introduced that prohibits clustering of investments that are more than one status away.

- Investments can only be clustered if they are at maximum 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 realizing the same function because they are commissioned too far ahead in time.

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

Figure 5: Clustering of investments: the categories marked in green in each line can be clustered, e.g. the main investment with status "permitting" can either be clustered together with investments that are "planned, but not yet in permitting" due to the second line or "under construction" due to the third line

[7] Where the term "significant delay" has to be seen case-specific in relation to all investments in that project: the investment with the earliest commissioning date might be longer delayed compared to that with the latest commissioning date.

3.2.2 TRANSFER CAPABILITY CALCULATION

There are two notions of transfer capability that guidelines refers to: Net Transfer Capacity, which 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 Capability, which is related to physical power flows that can be accommodated by the grid.

The **Net Transfer Capacity (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 area (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 of 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.

Since the exchanges between bidding zones result in power flows making use of the transport capacity across the different boundaries they impact, an increase in Grid Transfer Capability across a specific boundary is "ceteris paribus" illustrative of the increased exchange capability between these bidding zones. The "ceteris paribus" statement 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.

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 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[8] across the boundary under consideration. This figure applies to the year-round situation (i.e. 8,760 hours) of how the

[8] It has to be mentioned that the methodology on how the generation power-shift is applied can have a significant impact on the results and must thus be transparently 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.

generation power shift affects the power flow across the boundary under analysis. Calculating a 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 which 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 in at least 30% of the year). This is illustrated in Figure 6.To refine the assessment, seasonal delta NTC could be used instead of a single annual NTC.

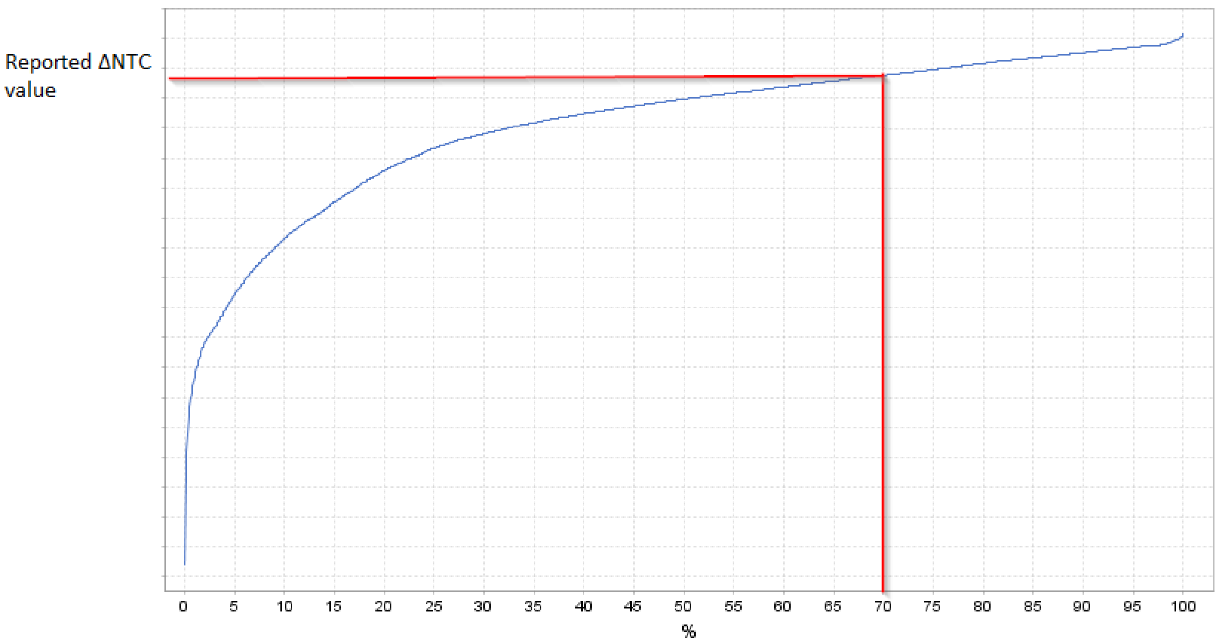

Figure 6: Duration curve of ΔNTC in one direction (blue) with 70th percentile (red): the reported ΔNTC at the 70th percentile needs to be reached in at least 30% of the time – at the right of the red line.

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

The **Grid Transfer Capability (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 which 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 circuits that make up the boundary 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. The project thus delivers a ΔGTC of 600 MW.

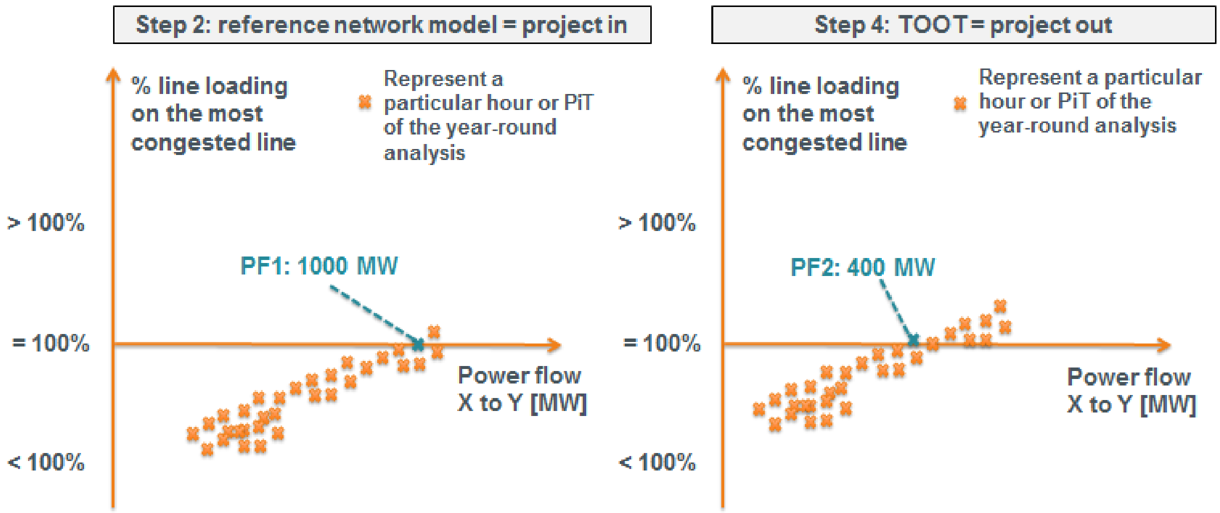

Figure 7: Schematic illustrating the calculation of ΔGTC

The additional GTC can be used for accommodating additional physical flows across a boundary that are the result of: 1) increased market exchanges between directly neighbouring bidding areas; 2) increased transit flows resulting from market exchanges between other European countries; and/or, 3) increased loop flows. All 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 transfer capability must be reported in a CBA assessment for a project at an investment level. 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. In any case, for each project, it has to be transparently 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 consistent and transparent way for all projects that are under assessment.

3.2.3 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. The geographical scope of the analysis is an ENTSO-E Region at minimum, including its closest neighbours. In any case, the study area shall 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[9]. Finally, in order to take into account, the interaction of the pan-European modelled system, exchange conditions will be fixed for each of the simulation time steps, based on a global market simulation[10].

Project appraisal is based hence on analyses of the global (European) increase of welfare[11]. This means that the goal is to bring up the projects which are the best for the European power system.

3.2.4 Guidelines for project NPV calculation

The Net Present Value (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. The NPV is used to assess the profitability 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.

To calculate the Net Present Value (NPV) of a project its monetized costs and benefits must first be estimated using the same assumptions (e.g. real, constant year-of-study values). These costs and benefits are incurred at different times and are discounted to the time for which the assessment is needed (i.e. the year in which the study is performed) using a discount rate. Discounted costs (negatives) and benefits (positives) can then be compared in order to calculate the NPV of the project.

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 (i.e. excluding inflation).

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

The analysis period starts with the commissioning date of the project and extends to a time-frame covering the economic life[12] of the assets. The period should recognise that asset economic life-spans vary depending on the technologies employed.

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

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

[11] 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 Power for caveats on Market Power and cost allocation).

The following main principles shall be applied when verifying the NPV[13]:

- Although it is acknowledged that there might be different discount rates per country, a common discount rate needs to be used for the purpose of consistent assessments;
- The economic lifetime is the period of time for which the asset remains useful and for which it is prudent to calculate social benefits and costs;
- Costs and benefits are to be expressed as real, constant year-of-study values;
- The residual value of the project at the end of the assessment period should be treated as having zero value for the purposes of consistent analysis. It is generally recommended to study at least two horizons: one mid-term and one long-term (see Chapter 2.1) horizon. To evaluate projects on a common basis, benefits should be aggregated across 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.

3.3 Assessment framework

The assessment framework is in line with Article 11 and Annexes IV and V of Regulation (EU) 347/2013. The criteria set out in this document have been selected on the following basis:

- They facilitates the description of project benefits in terms of the EU network objectives to:
  a. Ensuring the development of a single European grid enabling EU climate policy and sustainability objectives (i.e. RES, energy efficiency, CO_2);
  b. Guaranteeing security of supply;
  c. Complete the internal energy market, especially through a contribution to increased socio-economic welfare; and
  d. Ensuring system stability.
- They provide a measurement of project costs and feasibility (especially environmental and social viability indicated by the residual impact indicators).

[12] Economic lifetime of an asset: period over which an asset (i.e. the investments representing the project: a transmission line, a storage facility, a transformer etc.) is expected to be usable, with normal repairs and maintenance, for the purpose it was acquired, rented, or leased. The economic lifetime is the period over which it is considered to be prudent to calculate the social costs and benefits and is therefore equivalent to the evaluation period.

[13] See also the "Commission Implementing Regulation (EU) 2015/207" Annex III

- The indicators used are as simple and robust as possible. This leads to simplified methodologies for some indicators.

Figure 8**Error! Reference source not found.** shows the main categories of indicators used to assess the impact of projects on the transmission grid. The full detail of indicators is shown in Section 3: Main Categories of the Project Assessment.

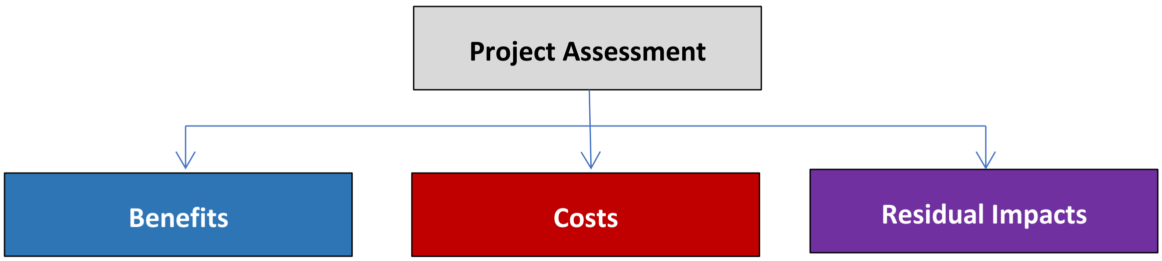

Figure 8 Overview of the main categories of CBA indicators

3.4 Benefit indicator

According to Regulation (EU) 347/2013, the present 3rd CBA guideline establishes a methodology for project identification and for characterisation of the impact of projects. The benefit indicators are described in detail starting from Section 3: Main Categories of the Project Assessment. Their detailed methodologies are captured in corresponding Sections. These methodologies include the elements described in Article 11 and Annexes IV and V of the Regulation. Note that projects may also have a negative impact on some indicators, in which case negative benefits are reported.

3.5 Project level based on promoters' input

For the purposes of the TYNDP process the 3rd CBA guideline introduces Project level indicators. These indicators represent benefits or costs of a project (transmission or storage), which have been identified as important for a complete Cost-Benefit Analysis, but that ENTSO-E is not able to assess at a Pan-European level within the TYNDP process. For these indicators the 3rd CBA guideline provides a definition, a clear perimeter of application and a methodology that must be followed in order to properly assess them.
Although the Pan-European nature of these indicators is recognized, it is acceptable to assess them relying on a regional or even national perimeter to deal with their inherent complexity (as for example the use of a redispatch approach[14]).
The 3rd CBA guideline then includes the possibility, within the TYNDP process, to include the submission of these indicators by the competent project promoter until TYNDP ENTSO-E processes are able to provide a Pan-European assessment.

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

The project level benefits identified in the 3rd CBA guideline are the following:

- **B7.1: Balancing Energy Exchange**
- **B9: Avoidance of the renewal/replacement costs of infrastructure**
- **B10: Synchronisation with Continental Europe (for Baltic States)**
- **B11: Reduction of necessary reserve for re-dispatch power plants**

All the other indicators presented in the Guideline which have not been listed above or are not computed applying a redispatch methodology do not fall into the "Project level indicator" category for the purposes of the TYNDP process. How these indicators should be assessed and described in the TYNDP project sheet is addressed in the sections dedicated to each indicator. Implementation details for the assessment of these benefits are also described in great detail 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. Name of the study;
    b. Year of the study;
    c. Company name that has performed the study.
2) **Link or copy of the study should be made available according the terms of the TYNDP process. The study must contain the following set of information:**
    a. Assumptions: detailed explanation of the assumptions used. The assumptions required for each project level benefit are detailed in the Section dedicated to that benefit;
    b. Data source (if requested the promoter should also be able to provide the data set used);
    c. Indication of the tool(s) used to compute the benefit;
    d. Clear explanation on how the methodology illustrated in this guideline has been implemented and applied to perform the study;
    e. Clear demonstration that the figures provided in the study relate to countries within the ENTSO-E perimeter only.

The mere submission of the project level benefit does not guarantee that the indicator submitted is considered valid. The validity of the project level benefit will be verified by ENTSO-E during a review process built-in the wider TYNDP process.

3.6 Costs

The costs include the CAPEX (indicator C1) and OPEX (indicator C2) incurred throughout the investment lifecycle. These are required to be reported for each investment in the price base year as set by the study.

Project expenditure, as reported by C1 and C2, shall be reported[15] including the corresponding uncertainty range.

3.7 Residual impact

As far as environmental and social mitigation costs are concerned, the costs of measures taken to mitigate the impacts of a project should be included in the project cost (indicator C1). Some impacts may remain after these mitigation measures are implemented. These residual impacts are accounted for by and included in indicators S1, S2 and S3. This split ensures that all measurable costs are taken into account, and that there is no double-accounting between these indicators.

4 Assessment of storage

The principles and procedures described in this document, for combined Multi-criteria and Cost Benefit Analysis, may be used for the evaluation of centralised[16] storage devices on transmission system. These Multi-criteria and Cost Benefit Analysis are applicable both to storage systems planned by TSOs and both by private promoters, even if a distinction on different roles and operation uses between these two types must be done. In fact, the possibility of installing storage plants on the transmission grid by TSOs is directly connected to the objective of improving and preserving system security and guaranteeing cost-effective network operation without affecting internal market mechanisms, nor influencing market behaviour.

Storage plants can be very easily introduced in market studies, since the existing facilities of this type are already modelled. Hence it can take into account some functioning constraints, and the losses 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 (income from activities in electricity markets), and a regulated-driven business model (income from regulated services). The CBA will not account for these differences[17]. As for transmission, it will yield monetised benefits of storage using a perfect market assumption (including perfect foresight), and account for non-monetised benefits using the most relevant physical indicators. However, if project promoters, i.e. a TSO or a private owner, have methodologies available allowing them to differentiate between these two use cases, they should use them and document them transparently.

The characterisation of the impact of storage projects can be evaluated in terms of added value for society as improvement of security of supply, increase of capacity for trading of energy and balancing services

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[15] Project costs must be reported as pre-tax values.

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

[17] It should be noted the 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.

between bidding areas, RES integration, variation of losses and CO_2 emission, adequacy, flexibility, and system stability.

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 Section 20: Assessment of Storage Projects.

5 Concluding remarks

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 in accordance with Regulation (EU) 714/2009 of the 3rd Legislative Package.

Following Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure, it also serves as a basis for a harmonised assessment of PCIs at the European Union level.

Starting from this version, the CBA is built with a modular approach: this will enable all the relevant stakeholders to better follow-up the future updates on a singular indicator. In the Sections of the 3rd CBA guideline, every indicator has its full description and perimeter, and for every indicator, the methodology describes the principles and the requirements needed to properly assess it. Within the framework of its application for the TYNDP, the guidance will be accompanied by a dedicated implementation guideline.

This is the 3rd CBA guideline. It builds on the previous versions of the document and takes into account the feedback that we have received from our stakeholders and from industry. In particular, it takes into account feedback received from public workshops held at the end of 2017 and ongoing work through 2018. We thank those who contributed to the preparation of this guideline and recognise that the improvements made in this 3rd CBA guideline will continue to evolve to meet the needs of our stakeholders.

6 Sections

6.1 Section 1: General Definitions

Boundary

A boundary represents a barrier to power exchanges in Europe, or in other words: a boundary represents a section (transmission corridor) within the grid where the capacity to transport the power flow related to the (targeted level of) power exchanges 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 subareas.

Competing transmission projects/investments

Two or more transmission projects are regarded as competing if they serve the same purpose, i.e. they are proposed to achieve a certain transmission capacity increase, but not all (proposed) projects are needed to achieve the necessary transmission capacity that serves this purpose. Usually, but not exclusively, the competing transmission projects in such cases a) increase NTC on the same boundary; and b) its socio-economically viability is reduced as if assessed under the assumption that the other project(s) is (are) also realized – thus, the overall net benefit in realising both is lower than the sum of the individual net benefits. These are not exclusive criteria, however.

Current grid (starting grid)

This defines the actual/existing grid determined at a specific date 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 used to modify the market exchange across a specified boundary in order to find the maximum change in generation made possible by the grid. A generation power-shift can be seen as the deviation from the cost-optimal power plant dispatch (determined by market simulations) with the purpose to influence the grid utilisation[18]. For example, one can imagine the loading of a line across the boundary which separates System A from System B (with energy transported from A to B). Starting from this situation, generation can be incrementally increased in area A and decreased in area B. This process

[18] This also can 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 of course used to reduce the grid utilization and to heal congestions. But as seen below in this guideline the re-dispatch will also be used to determine the theoretical maximum grid utilization by bringing the system to the edge of security.

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.

Grid Transfer Capability (GTC)

The GTC is defined as the greatest (physical) power flow that can be transported across a boundary without the occurrence of grid congestions hereby taking into account the standard system security criterion.

Investment

An investment is defined as the smallest set of assets that together can be used to transmit electric power and that effectively add capacity to the transmission infrastructure. An example of an investment is a new circuit and 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. Since different scenarios may result in different power flows, the amount of capacity which is required to transport these power flows across a boundary and consequently the amount of investment needs, may differ from scenario to scenario.

Investment status

Investments are classified according to the following statuses:

- **Under consideration**: projects in the phase of planning studies and consideration for inclusion in the national plan(s) and Regional/EU-wide Ten Year Network Development Plans (TYNDPs) of ENTSO-E;
- **Planned, but not yet in permitting**: projects that have been included in the national development plan and completed the phase of initial studies (e.g. completed pre-feasibility or feasibility study), but have not initiated the permitting application yet;
- **Permitting**: starts from the date when the project promoters apply for the first permit regarding the implementation of the project and the application is valid;
- **Under construction**;
- **Commissioned**;
- **Cancelled**.

Main investment

The investment initially planned to achieve a certain goal, e.g. the interconnector between two bidding areas. In order to achieve the full potential of the investment to achieve this goal, additional investments may be needed. A project that consists of more than one investment is thus defined as a main investment with one or more supporting investments attached to it. In that case, when clustering investments, one must explicitly define a main investment (e.g., an interconnector), which is supported by one or more supporting investments.

The full potential of the main investment represents its maximum transmission capacity in normal operation conditions.

Net Transfer Capacity (NTC)

The Net Transfer Capacity is a concept used in market models to represent the exchange capability between bidding zones. The NTC is defined by the maximum foreseen magnitudes of exchange programmes that can be operated between two bidding zones and should respect the system security conditions of the involved areas. As used for the application in the 3rd CBA guideline the NTC has to be interpreted as a best estimated forecast to determine the ΔNTC for simulation purpose only.

Planning cases

Representation of how the generation and transmission system could be managed one year along. The planning cases are point in time (snapshots) scenarios in order to represent in full detail the grid situations at these moments. Planning cases used in network studies 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 spell; and c) results of pan-European Power Transfer Distribution Factor analysis (PTDF, when available).

Project

A project is defined as a) a main investment that is built to fulfil a certain goal (e.g. to increase the capacity across a certain border by a certain amount), and b) one or more supporting investments that must be realised together with the main investment in order to make it possible for the main investment to realize its intended goal i.e. the full potential that is defined as the capacity increase of the main investment. In case there are no supporting investments needed, the project consists of just the main investment but will be nonetheless named '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 network that includes all investments needed to reach the level of transfer capacity set as reference for a specific scenario and time horizon.

The reference network guides the application of the TOOT and PINT principles, i.e.:

- Investments within the reference network are assessed via TOOT; and

- Investments on top of the reference network are assessed in PINT.

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 and 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 emission due to the associated climate change.[19]
- 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.[20]

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 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 obligation as defined under Article 8, paragraph 10 of Regulation (EU) 714/2009.

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

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

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:

- AC – Alternating Current
- ACER – Europe Union Agency for the Cooperation of Energy Regulators
- aFRR – Automatic Frequency Restoration Reserve
- 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
- CEN – Continental European Network
- CIGRE – Council on Large Electric Systems
- DC – Direct Current
- DSR – Demand Side Response
- EC – European Commission
- EENS – Expected Energy Not Supplied
- ENTSO-E – European Network of Transmission System Operators for Electricity
- EPRI – Electric Power Research Institute
- ETS – Emissions Trading Scheme
- EU – European Union
- FCR – Frequency Containment Reserve
- FRR – Frequency Restoration Reserve
- GTC – Grid Transfer Capability
- HHI – Herfindahl Hirschman Index
- HVDC – High Voltage DC
- IEA – International Energy Agency
- ITC – Inter Transmission System Operator Compensation for Transits

- KPI – Key Performance Indicator
- LOLE – Loss of Load Expectation
- mFRR – Manual Frequency Restoration Reserve
- MSC – Mechanically Switched Capacitors
- MSR – Mechanically Switched Reactors
- NEC – Net Export Curve
- NPV – Net Present Value
- NRA – National Regulatory Authority
- NTC – Net Transfer Capacity
- OHL – Overhead Line
- OPEX – Operating Expenditure Cost
- PCI – Projects of Common Interest
- PINT – Put IN one at the Time
- PiT – Point in Time
- PTDF – Power Transfer Distribution Factor
- RES – Renewable Energy Sources
- RR – Replacement Reserves
- RSI – Residual Supply Index
- SEA – Strategic Environmental Assessment
- SEW – Socio-Economic Welfare
- SMC – Submarine Cable
- SOGL – Commission Regulation (EU) 2017/1485: Establishing a Guideline on Electricity Transmission System Operation
- SoS – Security of Supply
- TOOT – Take Out One at the Time
- TSO – Transmission System Operator
- TYNDP – Ten-Year Network Development Plan
- UGC – Underground Cable
- VOLL – Value of Lost Load
- VSC – Voltage Source Converter

6.3 Section 3: Main Categories of the Project Assessment

The main project assessment categories are illustrated in the figure below:

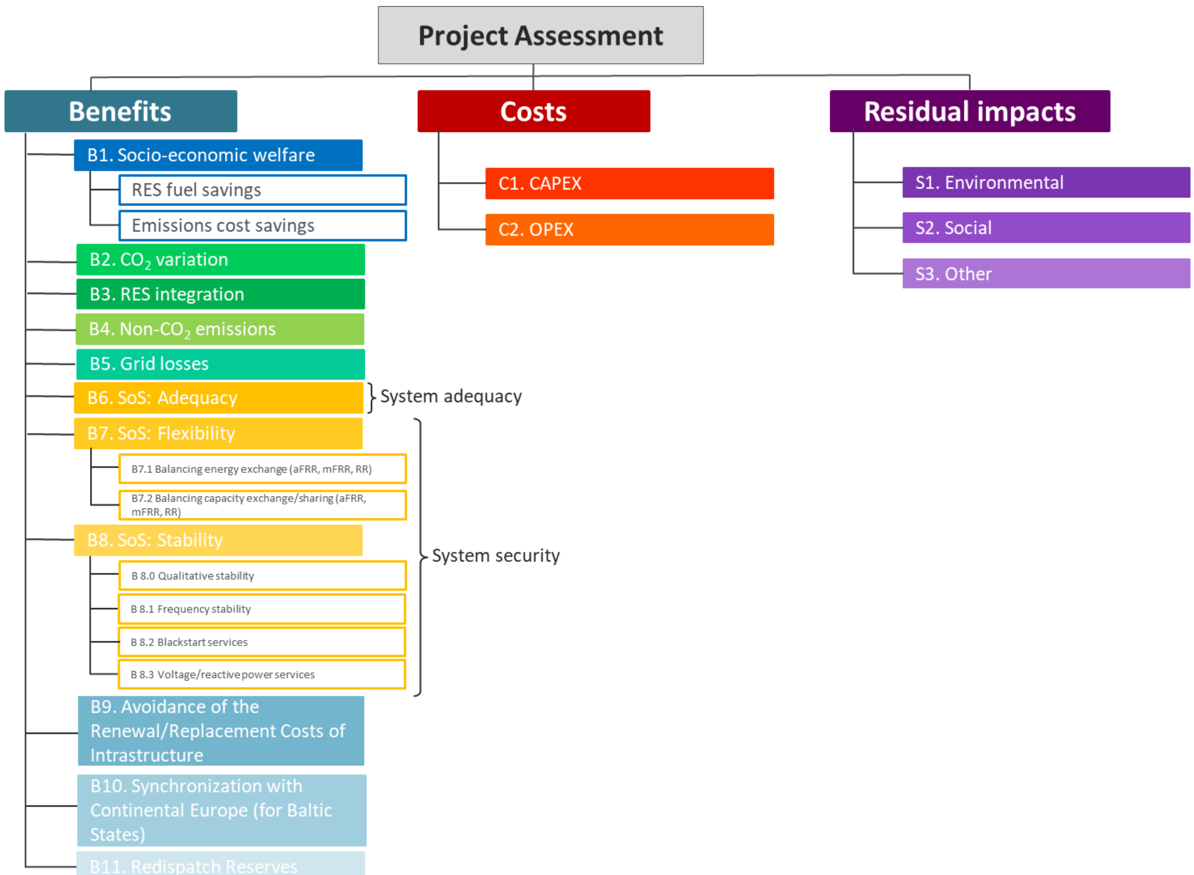

Figure 9: Main categories of the project assessment methodology

Benefits are defined as follows (see also Chapter 3.4):

B1. Socio-economic welfare (SEW from wholesale energy market integration)[21] is characterised by the ability of a project to reduce (economic or physical) congestion. It thus provides an increase in transmission capacity that makes it possible to increase commercial exchanges, so that electricity markets can trade power in a more economically efficient manner.

B2. Additional societal benefit due to CO2 variation represents the change in CO_2 emissions in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking renewable potential. The EU has defined their climate policy goals by reducing the greenhouse gas emissions by at least 40% until 2030 compared to the 1990 levels. As CO_2 emission is the main greenhouse gas coming from the electricity sector, they are displayed as a separate indicator. This indicator takes into account the additionally societal costs of CO_2 emissions.

B3. RES integration: Contribution to RES integration is defined as the ability of the system to allow the connection of new RES generation, unlock existing and future "renewable" generation, and minimising curtailment of electricity produced from RES[22]. RES integration is one of the EU 2030 goals which set the target of increasing the share of RES to 32% with respect to the overall energy consumption.

B4. Non-direct greenhouse emissions represent 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. It is a consequence of changes in generation dispatch and unlocking renewable 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[23] and 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 renewable energy sources production is taken into account.

B7. Security of supply: Flexibility characterises the impact of the project on the ability of exchanging 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

[21] 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.

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

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

(aFRR). Exchanging/Sharing balancing capacity (RR, mFRR and aFRR), which requires guaranteed/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 characterises the benefit a project can bring by avoiding or deferring replacing or upgrading already existing infrastructure.

B10. Synchronization with Continental Europe (CE)~~(for Baltic States[24])~~ is understood as safeguarding operational security, preventing the propagation or deterioration of an incident to avoid a widespread disturbance and the blackout state as well to allow for the efficient and rapid restoration of the electricity system from emergency or blackout states. Small systems (e.g. Baltic States) or poorly connected systems (regions) to face with major issues: work in "island" mode or strongly reliant on third countries' infrastructure. Therefore, synchronization with CE usually leads to improved system security and economy of operation.

B11. Redispatch Reserves or **Reduction of Necessary Reserves for Redispatch Power Plants** characterizes the project's impact on needed contracted redispatch reserve power plants by assessing the maximum power of redispatch with and without the project. Prerequisite for this indicator is the use of redispatch simulations.

Costs are defined as follows (see also Chapter 3.6):

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 cost of similar projects). CAPEX is expressed in euros.

C2. Operating expenditure (OPEX). These expenses are based on project operating and maintenance costs. OPEX of all projects must be given on the actual basis of the cost level with regard to the respective study year (e.g. for TYNDP 20 the costs should be given related to 2020) and expressed in euro per year.

Residual impact is defined as follows (see also Chapter 3.7):

S1. Residual Environmental impact characterises the (residual) project impact as assessed through preliminary studies and aims at giving 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 at giving a measure of the social sensitivity associated with the project.

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

These three 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 **project assessment** has to be carried out based on the eleven benefit indicators mentioned above, as well as the three residual impact indicators and the investment costs. Whilst the benefits should be given for each study scenario (e.g. the TYNDP visions), costs and residual impacts are seen as scenario independent indicators. In addition, 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[25]. For those countries that have not reached the minimum interconnection ratio as defined by the European Commission, each project must report the contribution to achieving this minimum threshold.

While the increased transfer capacity contribution and costs are given per investment, the benefit indicators and the residual impact indicators are provided at the project level. The contribution to transfer capacity is time and scenario dependent, but a single or seasonal value should be reported for clarity reasons. This value should reflect the average transfer capacity contribution of the project.

All monetary costs and benefits shall be reported in EUR and shall be expressed in the price level of a single base year to ensure comparability. The price base year to use for reporting monetary costs and benefits shall be explicitly defined in the context of each study (e.g., €2020 in TYNDP 20). ENTSO-E aims to monetize as many indicators as possible, but the required data is not always available (e.g. detailed emission prices per fuel type for non-CO_2 calculations) or monetization is the result of political preferences (e.g., the price of CO_2 is dependent on future political choices, but the amount of CO_2 equivalent emissions avoided by a project is not). 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 ENTSO-E believes it is more useful to publish indicator results in their original units than to unilaterally decide on their monetary value in an arbitrary manner. The table below provides an overview of the status with regard to monetization of the benefit indicators included in this 3rd CBA guideline:

Indicator	Original unit	Monetization status		Chapter in this document
B1. SEW	€/yr	per definition monetary		Section 4: Methodology for Socio-Economic Welfare Benefit (B1)
B2. CO_2 emissions	tonnes/yr and €/yr	Part 1: fully	Political CO_2	Section 5: Methodology for

[25] 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 on 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 % …"The interconnection ratio is obtained as the sum of importing GTCs/total installed generation capacity

		monetized under B1, where the effects of CO_2 emissions due to the assumption with regard to emission costs are monetized and reported as additional information under indicator B1. Part 2: this part is related to the additional societal value which is not monetized under B1.	reduction goals are formulated in percentages to values expressed in tonnes per year. The magnitude of the additional monetary effect is topic of an ongoing and controversial political debate. Therefore, the CBA guideline requires that CO_2 emissions are reported separately (in tonnes).	Additional Societal benefit due to CO2 variation (B2)
B3. RES integration	MW or MWh/yr	fully monetized under B1, where the effects of RES integration on SEW due to the reduction of curtailment and lower short-run variable generation costs are monetized and reported as additional information under indicator B1.	Political RES integration goals are formulated and expressed in MW. The magnitude of the additional monetary effect (on top of B1 and B2) cannot be monetised in a subjective way. 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	tonnes/yr	not monetized		Section 7: Methodology for Non-direct greenhouse emissions Benefit (B4)
B5. Grid losses	MWh/yr	Monetized 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	Monetized, provided that VOLL-values are available. The additional adequacy margin may be conservatively monetized on the basis of investment costs in peaking units, provided that figures are		Section 9: Methodology for Security of Supply: Adequacy to Meet Demand Benefit (B6)

		available.		
B7. SoS: Flexibility (balancing energy exchange)	ordinal scale	Not monetized.	At present not monetized due to 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 monetized.	At present not monetized due to 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	€			Section 12: Methodology for Avoidance of the Renewal / Replacement Costs of Infrastructure (B9)
B10. Synchronization with Continental Europe	€	Monetization is recommended under indicators B6, B7 and B8. This indicator is related to the additional societal value due to synchronization with CE.	Geopolitics risks and EU political roadmap of Baltic States full integration to CE (political, economic and technical structures)	Section13: Methodology for Synchronization with Continental Europe (B10)
B11. Redispatch Reserves	€/yr	Monetized 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	Section 21: Redispatch simulations for project assessment

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 contain all specifies 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 the necessary details that are 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 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.

The table below contains a summary of details for certain indicators that are to be defined complementary documents with focus on the TYNDP process. If applied to other studies these details must also be given within the respective study.

Indicator or rule	**To be defined in:**	**Info needed to be provided**
Simulation tools used to perform the assessment	To be defined within the documentation of the TYNDP	List of used tools 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)
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 used methodology has to 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-CO_2 Emission	Implementation Guidelines	List of emission types and factors per generation category
B5. Variation in Grid Losses	Implementation Guidelines	-Monetization 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 -the information whether points in time have been used together with 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
B10. Synchronisation with Continental Europe	Given by the project promoters or in Implementation Guidelines	Definition of the assumptions needed to be taken (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

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

In the field of energy economics, socio-economic welfare is understood as the sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners (congestion rent). Transmission expansions 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 due to a transmission bottleneck.

Scope of the indicator

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 in the TYNDP are 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 one to assess the marginal benefits of a transmission project against a 'static' reference framework. In reality, the transmission project actually alters the reference framework itself – albeit with an (often significant) time delay. Considering these longer-term effects makes the modelling challenge considerably more complex and decreases the robustness of results. The strength of an approach based on reporting the marginal differences in short-run surplus lies in its unambiguity.

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 of (related and unrelated) further (political) decisions.

In order to calculate the change in short-term economic surplus, a perfect market is assumed with the following assumptions:

- Equal access to information by market participants,
- No barriers to enter or exit,
- No market power.

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

a) The generation cost approach, which compares the generation costs with and without the project for the different bidding areas.

b) 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[26].

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, since 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 below in Figure 9. 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 below.

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 CO_2-Price.
Start-up-costs / Shut-down costs	These terms reflects 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.
DSR-Costs	Costs for Demand Side Response (DSR). DSR is load demand that can be actively changed by a certain trigger.

Table 1: cost terms used in market simulations

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

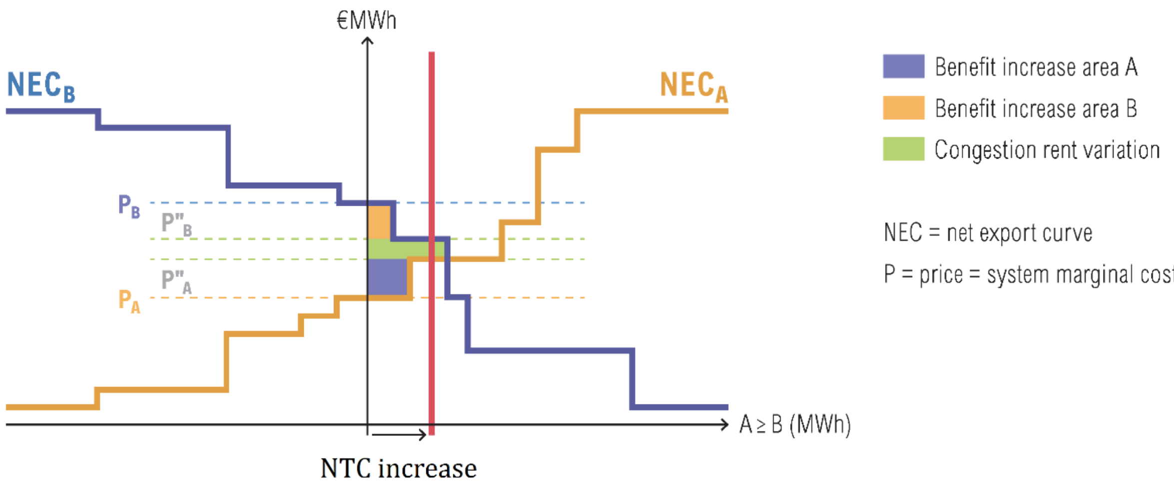

Figure 9: Illustration of benefits due to NTC increase between two bidding areas -+

If demand is considered as elastic, modelling becomes more complex. The choice of assumptions on demand elasticity and methodology of calculation of benefit from socio-economic welfare is left to ENTSO-E's Regional Groups. Most European countries are presently considered to have price inelastic demand. However, there are various developments that appear to cause a more elastic demand-side. The development of smart grids and smart metering, as well as a growing flexibility need from the changing production technologies (more renewables, less thermal and nuclear) are drivers towards a more price-elastic demand.

There are two ways of taking into account greater flexibility of demand when assessing socio-economic welfare, the choice of the method being decided within ENTSO-E's Regional Groups:

1) 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 has to be met, while at the same time considering different scenarios of demand-side management.

2) Introduce hypotheses on level of price elasticity of demand. Two methods are possible:

   a. 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.

b. 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.

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 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 Power), 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 simulations or considering virtual smaller bidding areas (with different market prices) separated by the congested internal boundary inside an official bidding area (see Chapter 2.2 Cross-Border versus Internal Projects). In any case it has to be transparently highlighted what method was used for the SEW calculation.

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.

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 of congestion rent (difference of 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 . 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. Finally, reducing network bottlenecks will lead to a change in total congestion rent for the TSOs.

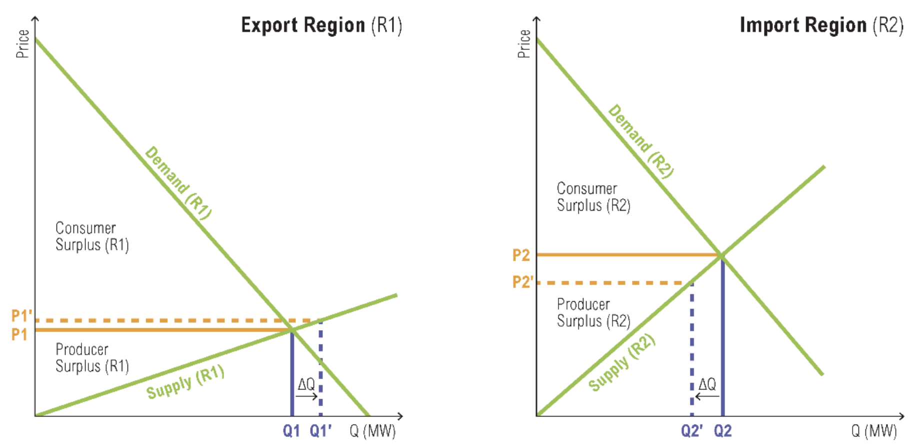

Figure 11: Example of a new project increasing transfer capacity (ΔQ) between an export and an import region.

A project with a GTC 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.

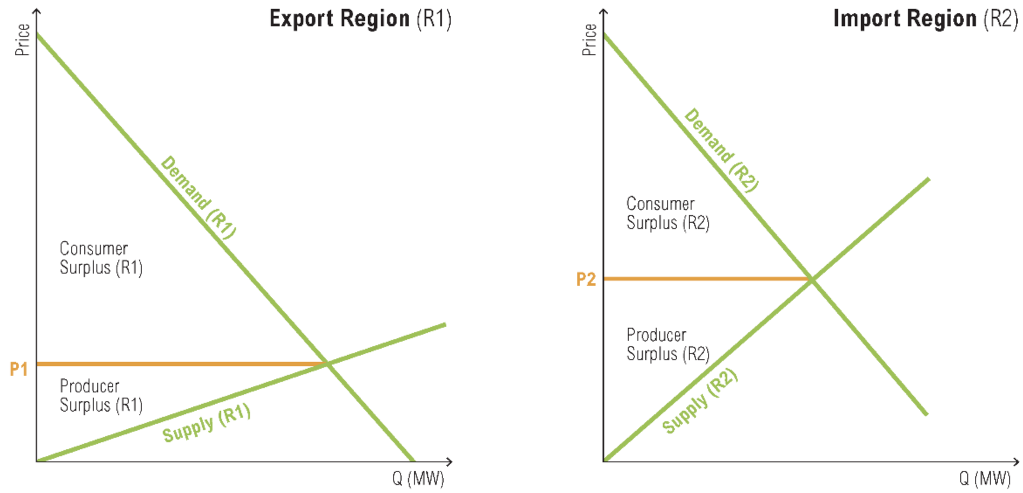

Figure 12: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity (elastic demand)

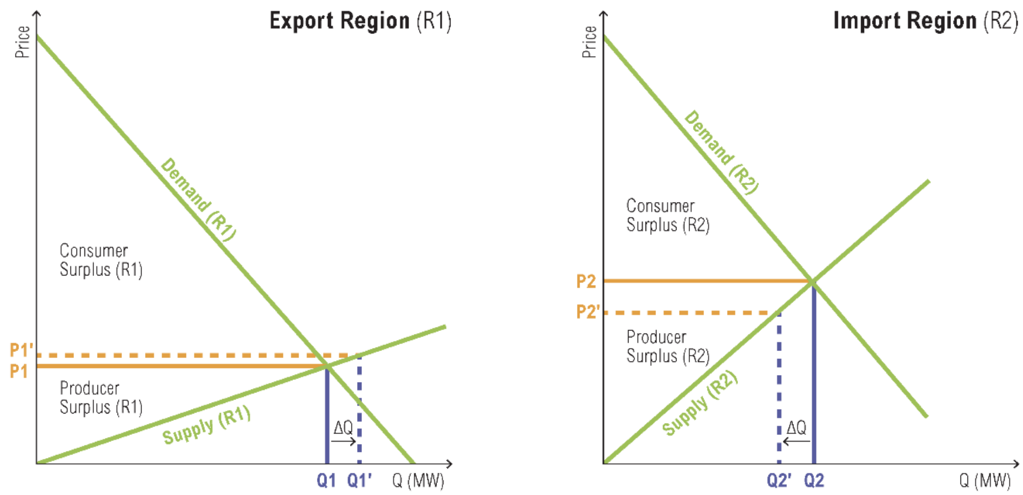

Figure 13: Example of an export region and an import region, with a new project increasing the GTC between the two regions (elastic demand)

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 area. 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 maximized when the market price is 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, since customers do not respond directly to real-time market prices (no willingness-to-pay-value is available). The change in consumer surplus[27] can be calculated as follows:

For inelastic demand: change in consumer surplus = change in prices multiplied by demand

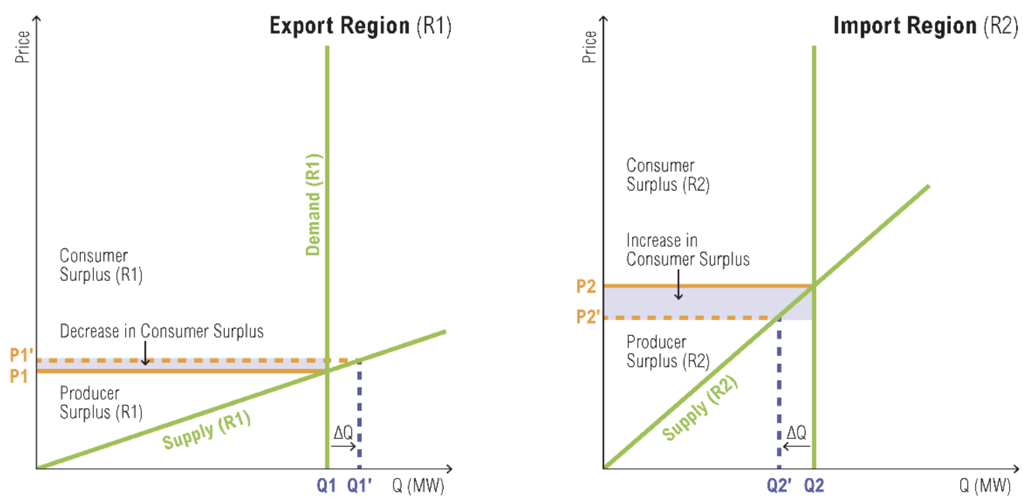

Figure 14: Change in consumer surplus

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[27] 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)$_{\text{without the project}}$

The change in producer surplus can be calculated as follows:

Change in producer surplus = change in generation revenues[28] – change in marginal generation costs

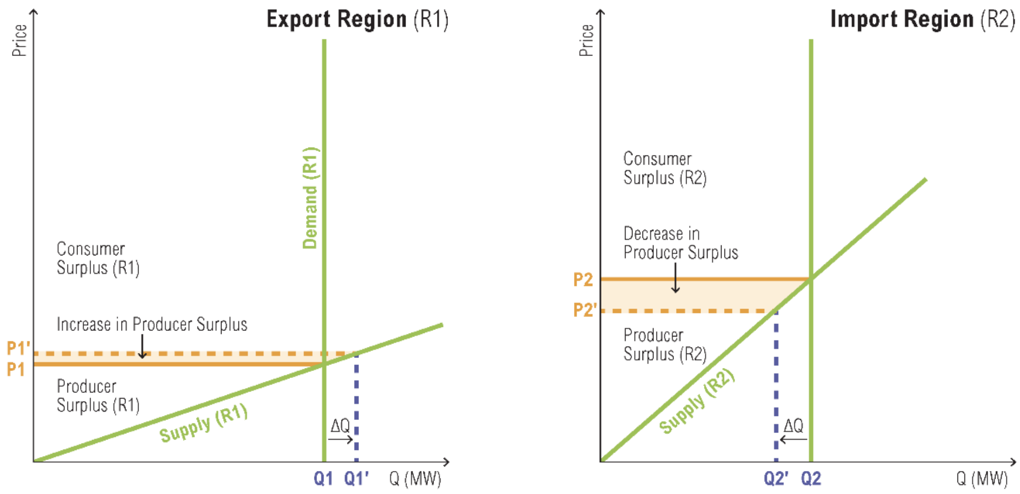


Figure 15: Change in producer surplus

The congestion rents with the project can be calculated by the price difference between the importing and the exporting area, multiplied by the additional power traded by the new link[29].

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 area

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 summarizing the benefit for all the hours of the year, which is done through market studies.

[28] Generation revenues equal: (marginal cost of the area x total production of the area).

[29] In a practical way, it's calculated as the absolute value of (Marginal cost of Export Area – Marginal cost of Import Area) x flows on the interconnector.

Results

Changes in SEW must be reported in €/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 those that are the result of variations in CO_2-emissions must be reported separately:

a) Fuel savings due to integration of RES;
b) Avoided CO_2 emission costs.

An overview of the different methods to calculate the SEW is given in Table 2.

Monetisation

This indicator is measured in €/yr and thus is monetized by default.

The effects of CO_2 emissions due to the assumption with regard to emission costs are monetized 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 monetized and reported as additional information under indicator B1.

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: Reduced generation costs/ additional overall welfare for the virtual bidding areas methodology	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

Table 2 Overview of the different methods to calculate the SEW

Table 3 Reporting Sheet of this Indicator in the TYNDP. Independent of the methodology used to calculate the SEW, the result will be given as a ***single*** *value in €/yr 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, either the virtual bidding areas or 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.

6.5 Section 5: Methodology for Additional Societal benefit due to CO2 variation (B2)

As confirmed by the signature of the Paris Agreement, the European Union is committed to lower its carbon impact. The European Commission now call for a climate-neutral Europe by 2050. This common goal aims at limiting global warming and its harmful impact it has on the word. Electric system in Europe is an important CO_2 emitter. Grid development can modify those emissions. In particular, interconnector, in changing power plant generation plan, modify the CO_2 emissions over the electric system. Storage project can have the same effect.

In order to fully display the benefit that comes from reducing the CO_2 emissions due to a new project, this indicator is divided into two parts: 1) the change of pure CO_2[30] emissions given in tons and 2) its monetarisation. The monetary part of CO_2 is partly taken into consideration within SEW and losses through the generation cost. Indeed, 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 by the producers, is the forecast of the CO_2 price over the Emission Trading Scheme (ETS). However this market price doesn't give a sufficient price signal to lead investment towards the one needed to reach our climate goal. Indeed the ETS price seems to be too low.

Thus, in order to appropriate 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 CO_2 emission variation are valued at the level of a societal cost. This cost represents the effort that should be made in order to reach the European goal.

Methodology

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

- Resulting from the change of generation plan
- Resulting from the change of losses volumes

In order not to double account with the CO_2 variation already monetized into the SEW and the losses, change in CO_2 emission is then multiplied by the difference between the CO_2 societal cost and the ETS price used in the scenario:

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

Example: hypothetical project A-B

Impact on CO_2 emission of change in generation plan (market simulations): -0.8 Mton/yr
Impact on CO_2 emission of losses volume changes: +0.2 Mton/yr

[30] 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.

ETS price in the scenario: 27 €/ton
Societal cost: 163 €/ton[31]
B2 benefit = (0.8 – 0.2)*(163 – 27) = 81.6 M€/yr

Note : because the double accounting of the ETS costs, that are considered already under the B1 indicator, have been considered within the calculation of B2 by subtracting the ETS costs from the total societal costs, this benefit (B2) is to be added to the overall monetary benefits.

CO_2 cost

By relieving network congestion, reinforcements, enable cheaper generation to generate more electricity, thus replacing more expensive conventional plants (with higher or lower carbon emissions). Depending on the assumed CO_2 price, it may lead to higher or lower CO_2 emissions expressed in tonnes. Considering the specific emissions of CO_2 for each power plant and the annual production of each plant, the annual emissions at power plant level and perimeter level can be calculated and the standard emission rate established.

Monetisation

The CO_2 cost used should be based on scientific works and international studies and, due to the expected spread of values from different sources, ideally 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.[32]
- 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.[33]

It is important to emphasize that this 'societal cost of CO_2' is a different concept than the cost 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 internalized in production costs and has a direct effect on SEW; hence, it is fully captured by indicator B1 (and also reported as such alongside the B1 indicator). However, the cost of CO_2 imposed on electricity producers does not necessarily reflect the total societal effect nor gives the incentive necessary to reach European 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.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence

[31] This is only an example.
[32] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2
[33] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2

CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tonnes/yr	per definition not monetary	European
CO_2 emission from losses variation	Network studies (losses computation)	Tonnes/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

Table 4: Reporting Sheet of this Indicator in the TYNDP

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

Methodology

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:

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

This indicator provides a standalone value associated with additional RES available for the system. It measures the reduction of renewable generation curtailment in MWh (avoided spillage) and the additional amount of RES generation that is connected by the project. An explicit distinction is thus made between RES integration projects related to (1) the direct connection of RES to the main system and (2) 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 (1) is expressed in $MW_{RES\text{-}connected}$ (without regard to actual avoided spillage), whereas the capacity-based indicator (2) is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system[34]. Avoided spillage is extracted from the studies for indicator B1. Connected RES is only applied for the direct connection of RES integration projects. Both kinds of indicators may be used for the project assessment, provided that the method used is reported (see table below). 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).

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, network or redispatch studies	MWh/yr	included in generation cost savings (B1) and variation in CO_2 emissions (B2) **Error! Reference source not found.**	European

Table 5. Reporting Sheet of this Indicator in the TYNDP

[34] 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.

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).

6.7 Section 7: Methodology for Non-direct greenhouse emissions Benefit (B4)

Following the Paris Climate Agreement, the goal of reducing the greenhouse gases is to keep the global temperature increase below 2 degrees Centigrade as compared to pre-industrial levels. The main focus in achieving this goal is directed to 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). But on top of it, other, non-CO_2 emissions have to be considered, as their impact to the climate cannot be neglected. Furthermore, in general any kind of emission increases the pollution directly by emitting e.g. particulate matter, toxic elements, or indirectly by promoting chemical reactions causing e.g. acid rain. In order to properly take into account the mitigation effects of transmission and storage projects, specific effort also has to be taken for these non-CO_2 emissions. This should include at least the main emission types CO, NO_2 (including NO that reacts to NO_2 within the atmosphere), SO_2 and particulate ($PM_{2.5}$ and PM_{10}).

Methodology:

The amount of emissions of each type can be calculated as a post process based on the year round power plant dispatch as delivered by the market (redispatch) simulations by multiplying a specific emission factor in [t/MWh] to 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. Due to the fact that this is a very complex topic, for sake of simplicity, the emission model can be applied per technology type. It has to be noted that in general these emission types can differ for different countries dependent on the installed composition of power plants: e.g. more modern power plants in general will have a higher efficiency and therefore a lower emission factor and 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 due to 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 tonnes per year [t/yr].

Monetisation:

A monetisation of the non-CO_2 indicator is currently not proposed in this methodology, as it is not unlikely that future improvements on emission reduction due to filters or increase of efficiency can have a comparable effect at lower costs. When monetising the non-CO_2 indicator, it might turn out that projects will become beneficial/non-beneficial just due to this impact, which: i) is most likely not the main aim of building the project; ii) can strongly be impacted by future technologies. However, as 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.

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)	Tonnes/yr	per definition not monetary	European

Table 6: Reporting Sheet of this Indicator in the TYNDP. Each single emission type has to be given separately.

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

Introduction

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 must be noted, however, that the main driver for transmission projects is currently the need for transmission over long distances, which increases losses. Furthermore, losses are sensitive to the precise location of generation units.

Methodology

In order to calculate the difference in losses (in units of energy [GWh][35]) and the related monetisation attributable to each project, the grid losses have to be computed in two different simulations with the help of network studies: one with, and one without the project.

1. Relevant geographical area/grid model

   The calculated losses should be representative for 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 a **regional network model**. A regional model 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). An AC calculation should be used where possible or a DC calculation if convergence in the load flow tools is not reached.

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

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

2. Relevant period of time

   A calculation over the complete year, with sufficiently small time steps (typically one hour), should be aimed as being 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).[36]

3. Market results/generation pattern with and without the project or in grid stressed situations

   Since 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

Once the losses (i.e. in MWh) are calculated, they can be monetised. It is important, when monetisation is performed, 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 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:

- $p'_{h,i}$ (with project) and $p_{h,i}$ (without project) the amount of losses in MWh (after eventual measures for securing the grid situation);
- $s'_{h,i}$ (with project) and $s_{h,i}$ (without project) the marginal costs 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:

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

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

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 monetized result (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 case of loss of load (ENS). As a result, the marginal price during these hours do not represent society cost and if used for monetization, can distort the results. Thus, for each market node, the market price used for the losses monetization 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.

Parameter	Source of calculation[37]	Basic unit of measure	Monetary measure	Level of coherence of monetary measure
Losses	Network studies	MWh/yr	€/year (market-based)	European

Table 7: Reporting Sheet of this Indicator in the TYNDP

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 in which the effect of the change in marginal costs due to the project on the losses part of the demand is taken into account). Thus, 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 with 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 not to use a uniform European value. The compensation term, which has to be computed for both reference and TOOT/PINT cases, and then subtracted from the monetized losses, is the following (using the notations from above):

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

where K is the portion of the demand assumed to be losses, and $d_{h,i}$ is the demand on market node *i* in hour *h*.

[37] Cf Annex IV, 2c.

With this compensation, the monetized 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 e.g. 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 monetize the delta losses simplifies to the following:
  - In 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 case of TOOT projects:

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

where $p'_{h,i}$ and $p_{h,i}$ are the amount of losses in MWh with and without the project, and $s'_{h,i}$ and $s_{h,i}$ are the marginal costs with and without the project. The advantage of the method is that no data collection from the TSOs or assumptions are needed, but the computed losses might differ from the unknown losses that are included in the demand. The example below demonstrates how the simplified formulas can be obtained.

In the end, unsing this assumption, the losses calculation simplifies to a multiplicaiton of the delta in losses with just one single price (which one to use depends on whether TOOT or PINT has been used).

The assumption to be used is to be specified in the respective study (e.g. within the TYNDP Implementation Guidelines).

Example for additional explanation

A simple example is presented below for only 1 hour and 1 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 monetized 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**
  - $B = p - A$ for PINT projects and $B = p' - A$ for TOOT projects
- C: is the difference between the losses **with and without the project**
  - $C = p' - p$

Let's write *p* and *p'* using A, B and C (while 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 case of PINT projects and *p'* in case of TOOT projects).

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

In case of PINT projects:

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

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

In 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 monetized 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:

- Estimation of A:
  - after having calculated $\boldsymbol{p' \cdot s' - p \cdot s}$ a correction needs to be applied
  - assume A=2% of the load
  - then the correction (to be subtracted from the final result) will simply become:

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

- Assumption that the calculated losses are equal to the assumed losses, thus B=0:
  - then the monetized delta losses

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

can be reduced to

$C \cdot s'$ for PINT projects;

$C \cdot s$ for TOOT projects,

as B=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)

Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity in order to meet the demand at any moment in time, i.e. that 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 and etc.). In achieving this objective, generation and transmission capacity are complementary elements: generation capacity requires a transmission grid for power to flow from generation source to 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 to the adequacy by pooling the risk of facing loss of load and in 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 the stressed events of the countries are simultaneous, the higher is the adequacy benefit of a new interconnector. Indeed, 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:

- Decrease the need for generation capacity: for an equivalent SoS level (in terms of LOLE[38] and EENS[39]), an interconnector can decrease the peaking unit capacity needs;
- Decrease ENS volumes: when only one country is facing loss of load, a new interconnector can help to import more, hence reducing ENS.

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

For a project's Cost Benefit Analysis, the adequacy benefit must be taken into account. It can be assessed through two approaches. On the one hand, the decrease in peaking unit investment needs (for the same SoS level) can be used. On the other hand, the reduction of EENS volume (installed capacity remaining constant) can be considered. Some implementation difficulties incline 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 to make a link to the benefit that might be there for some countries that have capacity remuneration mechanism in place for adequacy purposes.

Whenever the year of the first mid-term horizon study year of the CBA 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).

[38] Loss of Load Expectancy
[39] Expected Energy Not Supplied

Prerequisites

Loss of load is a very scarce phenomenon, resulting of the combination of extreme events. As a result, studying loss of load requires a refined model of the hazards that could affect the electric 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 even grid) outages patterns.

Besides, studying adequacy requires generation portfolios to be adequate. This means that loss of load expectancy (LOLE) should be realistic and reasonable[40]. The scenario used to compute the SoS adequacy benefit must abide by this principle. It is advised 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. Thus, for TOOT projects, a small adaptation could be necessary if the countries are not adequate anymore once the project is removed. The adaptation would only consider adding a few peaking units.

Methodology

i. **Step 1**

If needed, adapt the scenario to get realistic LOLE levels without the project. The LOLE is considered realistic if it is in a range of 1h lower or higher to the LOLE legal standard.

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

This step is necessary because for some TOOT projects, removing the interconnector would lead to unrealistically high LOLE and consequently unrealistically huge 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 case of adequacy which is directly impacted by both generation capacities and interconnector levels. Thus, the slight adaptation may be needed for TOOT projects, which makes the assessment slightly conservative.

ii. **Step 2: EENS saved**

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

iii. **Step 3: Sanity check**

The sanity check is defined in order to cap the value computed by EENS savings to the value of the equivalent generation capacity that would have been necessary to reach an equivalent level of adequacy (compared with the addition of the project).

a. **Detailed sanity check**

[40] Using national adequacy standard for instance, if such standards don't exist, use 3h/yr.

i. Individual sanity check

For each country impacted by the interconnector (e.g. each country whose EENS decreases by adding the interconnector), a cap in terms of peaking unit investment saving is assessed. This cap is assessed separately for each country. This sanity check reflects that, for a country, the adequacy benefit cannot be higher than the cost of the peaking unit capacity that would give the same adequacy benefit than the interconnector. The process is as follows:

- Start without the project;
- Add peak power plants in the country until the adequacy level (EENS and LOLE) is equivalent to (or very slighter better than) the setup with the project.

This value gives a cap of the adequacy benefit brought by the interconnector to the country.

The cap is then monetized using the cost of new entry and is compared to the EENS reduction calculated at step 2: if for a country the cap is lower than the EENS reduction, then the adequacy benefit adopted for this country is lowered to the cap. At this stage, the global adequacy benefit is the sum of the minimum between the EENS reduction value and the sanity check for each country.

Note that the capacity of the interconnector gives an immediate cap: adding an X MW interconnector between two countries could not bring more adequacy benefit for each country than adding X MW of peaking units to its generation assets.

ii. Global sanity check

Perform a simulation without the project but with the capacities of the individual sanity check for the two countries linked by the interconnector. If the adequacy level is better for all the countries than the one reached when adding the interconnector, then these capacities can be used as a global cap. If the sum of the two capacities is lower than the adequacy benefit assessed at step 3.a.i, then the adequacy benefit is reduced to the global cap.

Note that for an X MW interconnector, a 2*X MW of peaking unit capacity is an immediate global cap.

b. Simplified sanity check

Instead of performing two sanity checks (individual and global), a simpler alternative is proposed. There are then two situations:

- ➢ Both side of the interconnector see SoS benefit: use **2 * interconnector capacity** as a cap to the global value.
- ➢ One side of the interconnector sees SoS benefit: use **1 * interconnector capacity** as a cap to the global value.

This simplified approached might lead to a slightly too high result due to the fact that lower generation capacity would have been needed in reality.

Examples

The table below presents a fictional example of the SoS benefit for a new 500 MW interconnector between two countries (A and B), while a third country (C) is also slightly impacted. The results after the three steps are depicted in the table (with detailed or simplified sanity checks[41]). The individual sanity check is useful only for A while the global sanity check is not useful because too high.

Example with individual and global sanity check

(M€/yr)	Country A	Country B	Country C
Step 2: EENS saved	20	12	1
Benefit after step 2		20+12+1 = 33	
Step 3.a: Individual sanity check	18 (< 20)	16 (> 12)	2 (> 1)
Benefit after step 3.a		18+12+1 = 31	
Step 3.b: Global sanity check		18+16 = 34 (> 31)	
Final value		**31**	

Example with simplified sanity check

(M€/yr)	Country A	Country B	Country C
Step 2: EENS saved	20	12	1
Benefit after step 2		20+12+1 = 33	
Step 3.c: simplified sanity check		Both sides are impacted -> two sided sanity check: 2*500MW -> 40M€/yr	
Benefit after step 3.c		33 > 40	
Final value		**33**	

Monetisation

This indicator is measured in €/yr and thus is monetized by default.

Parameter	Source of calculation[42]	Basic unit of measure	Monetary measure	Level of coherence of monetary measure
Level of Adequacy	Market simulations	MWh/year	€/year (market-based)	European

Table 8: Reporting Sheet of this Indicator in the TYNDP

[41] For the example, the cost of new entry is equal to 40 k€/MW/yr

[42] Cf Annex IV, 2c.

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

This section describes the methodology for a quantitative assessment (non-monetized) 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, the latter ones (DSR and participation of RES) are yet not possible to assess in an objective way.

The true valorisation of system flexibility – within the limits of a Guideline on Electricity Transmission System Operation (SOGL) - is ultimately the valorisation of the system needs & 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 the 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 that sense, ENTSO-E has started the analysis in order to investigate the setup of such market models, the acquisition of necessary data & hypothesis

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

Exchange and sharing of ancillary services products, in particular balancing energy exchanges, is crucial both to increase RES integration and to enhance the efficient use of available generation capacities.

The balancing services indicator shows welfare savings through exchanging balancing energy and through imbalance netting. Balancing energy refers to products such as Replacement Reserve (RR), manual Frequency Regulation Reserve (mFRR), 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 any of both directions (for 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 around the choosing the right balance between complexity and feasibility of completing assessments timescales and resource level. 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 indicated in the table below:

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

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 big impact on the Balancing Energy Exchanges indicator.

Additionally, within the study specific implementation guidelines, a detailed description on how the qualitative indicators have been defined shall be given.

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.

1. 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, PICASSO[43]. 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 to be rolled out as part of the balancing guidelines implementation are expected. This assumption can be tested and adjusted for projects where common platform is not foreseeable.

[43] Mandatory and required by Electricity Balancing Guideline (EBGL) to setup standard platforms for exchange of balancing energy towards 2022-2023

2. Balancing Needs[44]

A system imbalance that needs to be resolved is assumed. The volume needed 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 bid areas.

An 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 risks underestimating future balancing needs. It is strongly recommended to study the effects of this type of assumption.

3. 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.

4. 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 require necessarily 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 need for available cross-border capacity. The model should calculate the volume of imbalance netting that is possible.

5. Balancing Bids and Offers[45]

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:

5.1) Determine a seasonal average balancing bid prices using historical data;

5.2) Determine hourly national balancing bid prices curves, ie prices and volumes offered, using historical data;

5.3) Determine historical balancing bid prices savings exchanged through a balancing platform;

5.4) Determine hourly national balancing bid prices curves, ie 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).

[44] Balancing needs for upwards and downwards reserves
[45] Balancing bids and offers for upwards and downwards reserves

6. Balancing Cost Savings

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

MonetizationUntil 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.

Parameter	Source of calculation[46]	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

Table 9: Reporting Sheet of this Indicator in the TYNDP

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

This section describes the principles behind these kinds of flexibility services, but does not yet put forward a specific methodology to be applied to arrive to quantitative/monetized results, which need further analysis, investigation of correct hypotheses and testing within ENTSO-E. The final methodology should follow in respective study (e.g. the TYNDP implementation guideline) or in an updated version of this CBA guideline.

These kind of services are possible and allowed within & between synchronous areas (SAs), when operational limits are respected as specified in annex VII of the System Operation Guideline (SOGL), both between LFC-blocks as between LFC-areas of the same LFC-block and specifications of Art. 175-179 are respected. 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, which implies less volumes are blocked from participating in other markets (wholesale DA/ID, balancing, etc.) bringing potentially overall welfare. Specific grid development projects (both XB-lines as internal reinforcements that resolve congestions or limitations that would otherwise would 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)) can increase or unlock these potential welfare benefits , by giving access to more (potentially) cheaper assets that can deliver the FRR/RR service, provided the SOGL rules are respected & available cross border capacity is guaranteed, which can then theoretically result in a more optimal system operation & reducing overall system/fuel costs. The net welfare effect is however to be calculated & compared with

[46] Cf Annex IV, 2c.

the welfare calculations in other markets (e.g. wholesale) since for 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)

B8.0 Qualitative stability indicator

This section describes the methodology for a qualitative assessment (non-monetized) of stability, pending methodology developments 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 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 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 and would be 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. 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 below.

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	+	++	++

Table 10: Security of Supply: system stability indicator, given as qualitative indicator related to the different technologies

The indicators to be used in order to determine the impact on the relevant indicator are as follows:

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

0: 6No 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 big 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[47], this should also be highlighted by reporting N/A.

In addition to this qualitative stability indication, Table 10 can also act as indication where further investigations on transient, voltage and frequency stability might be interesting on the one hand side and where no further information is expected on the other side.

On top of that, 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 above. For such cases, the generic representation contained in the table above may be modified to appropriately represent the results of the technical studies. It is necessary that the supporting reports be provided to corroborate the assessments and any modifications to the table above. Currently, this quantitative assessment has been made concerning the impact of a reinforcement project on the frequency stability.

B8.1 Frequency stability

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

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 unbalance between generation and demand. 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 for estimating the system frequency behaviour of a power system to generation/load unbalances.

Using the proposed model for frequency stability calculations, a grid reinforcement project can be evaluated. Among them we can consider:

1. **HVDC interconnectors between synchronous areas;**

[47] 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.

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 one year:

- *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.

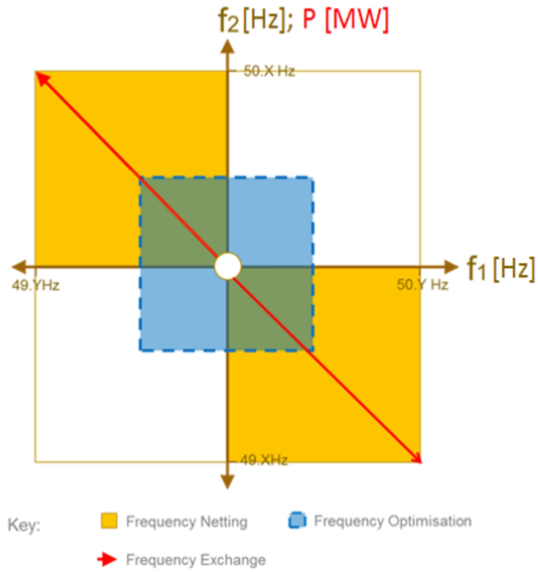
The computation of the indices is undertaken on an hourly basis over a timeframe of one year. The analysis is referred, at the planning level, to future systems scenarios foreseen in terms of hourly power generation by technology type and loads per European country. Considering reference values for generators in terms of rated capacity, constant of inertia and loading levels, the running capacity necessary to generate the output power from the market simulations is determined. It is possible then 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 on an energy level, based on either a frequency netting, optimisation of exchange is implemented (cfr. Section B8.1.2). The way the interconnector is used for FCR purpose should be reported as it must be consistent with the NTC used for the other indicators (if some capacity is reserved for FCR purpose, 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 kind of services, but does not yet put forward a specific methodology to be applied to arrive to quantitative/monetized results, which needs further analysis and testing. The final methodology should follow in the implementation guideline or in a next version of the CBA guideline.

Between Synchronous Areas (SAs) = "frequency coupling"

Between Synchronous Areas, frequency support services are officially known as "frequency coupling services", as described in SOGL. From 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) & frequency optimization (FO).



The specific limits & conditions to respect are described as well and included 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 line with the stipulations as set forward in Art. 171/172 of SOGL. Across HVDC-cables, such services can indeed be implemented and unlock specific benefits that could theoretically be monetized (FCR capacity exchange or sharing) or non-monetized (general increase of frequency quality).

Frequency netting & optimization contribute to the overall frequency quality of both connecting SAs. Those benefits cannot be monetized today 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 monetized, 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 capability of enabling such services (which should be included in the CAPEX). Principally, the assessment of those benefits could work as follows – pending further analysis and a final methodology in implementation guideline or a next CBA version.

For frequency netting & optimization: In case the frequency quality contribution is systematic, both connecting SA's could agree in a sharing agreement to reduce the overall amount of FCR obligation, provided the resulting frequency quality remains within legal limits as imposed by SOGL. In case this volume could be accurately & realistically estimated, welfare benefits from other markets (SEW in DA/ID/balancing markets) can be calculated due to a reduced overall FCR obligation.

For frequency capacity exchange: calculate the welfare benefits (SEW in DA/ID/balancing markets) by having allocated more optimally the overall FCR obligation. Warning: assumes that the allocation can be done in most optimal way, however in practice FCR auction clearing happens before DA clearing. The net effect can hence 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, hence theoretically there is no direct link to any grid development projects there– hence no direct benefits. However, only in the case where, as described in other SA's (non CE) or within LFC-areas of the same LFC-block within CE, internal congestions would be alleviated or a more even distribution of FCR can be obtained in 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, which can 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 monetize such benefits, such specific localized information should be available and integrated with other welfare calculations in DA/balancing markets, in order to determine the effective monetized benefit.

B8.2 Blackstart services

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

Blackstart reserves are contracted or imposed by TSOs for a certain minimum level (= the total need) on existing market flexible units in order to ensure the possibility of re-energizing the electric system after a contingency event which would have resulted in the loss of power supply in parts of or the entirety of a bidding zone or LFC block as a result of the contingency event. Such services are typically described & required by SOGL and usually also in 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), thereby potentially reducing the overall system costs and contributing to overall welfare in other markets (e.g. Wholesale or balancing markets) since more (typically peaking) units would become available as a result. The valorization of such benefits requires proper assumptions on the total volume need of black start reserves (and their required localization) 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, …) 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 valorization could also be the avoided investment in such black start services. It should be clear that this kind of benefit does not overlap with the adequacy indicator B.6, since blackstart services cannot participate in any other markets (adequacy, wholesale, balancing) by definition, since they need to be kept out to serve their sole purposes 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 for such services.

B8.3 voltage / reactive power services

Voltage or reactive power services/reserves are required from a TSO point of view in order to satisfy the SOGL regulation and usually 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 – potentially avoiding the need for investments and/or unlock 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) since more units would become available as a result. The valorization of such benefits requires proper assumptions on the total volume need of reactive power reserves (and their required localization) 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, …) 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 valorization 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)

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 TSO 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 thus 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 TSO.

Data Requirements

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 TSO's own cost estimates.

The precise nature of the capacity benefit of the new project needs to be determined and assurances are required that security of supply is not compromised as a result of the reliance 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.

Reference case

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 which includes the refurbishment.

Modelling and Calculation

The benefit is modelled as a once-off incremental benefit that is specific to the circumstances of the TSO and should therefore be applied only for refurbishment projects within the TSO'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 purpose, attention must be paid to the date to which the avoided investment would have occurred, in order to discount it properly. Moreover, there is a risk that the TSO represent the full benefit of the cost of the refurbishment of existing infrastructure to the new project when, for some cases, the benefit is only a deferment of refurbishment costs. In such a case, the TSO would have to carry the cost difference between the deferred refurbishment investments.

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

Table 11: Reporting Sheet of this Indicator in the TYNDP

6.13 Section13: Methodology for Synchronization with Continental Europe (B10)

The more power plants are connected in the electric power system, the more economical it is. The higher the total power of the power plants is, the higher power and more economical power plants units could be installed. For reliable and qualitative system operation, in the system the load of the most heavily loaded unit in operation shall normally not exceed 3 to 5 % of the total system load. That 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 energy systems can be installed with high power units that are more economical than small ones.

The larger energy system has different categories of consumers. The total load of such system is more stable. As system expand, the possibility of systems interconnection occurs. The interconnected systems must agree with the conditions of the controlled area. Such area is controlled by control that centre consist of a power system, or part of it, where:

- a balance of power and energy is always ensured;
- schedules of inter-system power exchanges are ensured with agreed accuracy;
- the frequency in the system is adjusted within the required range;
- to ensure reliable system operation the required power reserve is maintained and, can to help neighbour systems in case if needed (emergency or carry out repairs).

The interconnection of electric power systems advisable/purposive, because:

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

Small systems (such as Baltic States (Latvia, Estonia, Lithuania)) or poorly connected systems has operating costs for this day. However, regard to the long-term plans of the EU (climate policy goals and targets for 2030 or 2050 year), will meet with RES integration challenges, nonsynchronous generation, decrease of inertia, short circuit power, dynamic voltage stability, etc. problems. All these phenomena could lead to cascading outages and possibly a shut-down of systems (blackout). Small or poorly connected systems will be met with expensiveness of operating system control in the future. To avoid it or reduce operating costs such systems should synchronize with CE.

The Baltic electricity energy sector wasn't designed worked in "island" mode. Being an "energy island" strongly reliant on third countries' infrastructure, pose exceptional risks for system security, increased risks of blackout and undermine political and economic independence of the region.

Even though the Baltic States managed to eliminate its status of being an "energy island" and became integrated into common the EU internal energy market and de jure work according to EU regulations, technically Baltic States remain synchronously connected to the IPS/UPS system. This hinders full integration to EU electricity markets and European transmission grid.

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

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

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

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

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

CAPEX includes both the capital costs incurred at inception during the construction period; and capital expenditure incurred later in the project life-cycle.

In general, CAPEX would include the following categories:

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

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

Example:

- 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, while investment 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 of its commissioning. Thus, these the input the promoter should provide:

Table 12: Illustration of Capital Expenditure Information to be provided by Project Promoters

CAPEX [M€]		COMMISSIONING YEAR
INVESTMENT A	**40***	**2022**
INVESTMENT B	**10***	**2023**
INVESTMENT C	**20***	**2024**

[Note*: the investment costs are real values in 2020 (for TYNDP2020-30) terms]

The provision of the capex expenses in this way permits the comparison of the project with other projects since 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.

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 transparently explained uncertainty range[48].

- **For non-mature investments in the "planned, but not yet in permitting" or "under consideration" status**

  1. If detailed project costs information is available: these should be used and applied the same principle for mature investments should be applied.
  2. If detailed project costs information is not usually available, the project promoters will be required to use standard investment costs to be provided by ENTSO-E in the context of the TYNDP. These costs are to be multiplied by a clearly defined project-specific complexity factor. Regarding the definition of the complexity factor, three situations should be applied:
     a. Giving a range for the standard costs per group of assets that includes a maximum and minimum value according its expectations without project promoter explanation (see table below[49]);
     b. In the case where the project promoter chooses complexity factors that exceed the previous ranges, the choice should be explained as clear manner as possible. 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;

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

[49] Taken for example from the ACER report according with minimum and maximum interquartile.

c. In case project promoter do not know anything about the project investments costs in this non-mature phase (including the effect of possible impacts of project characteristics), this costs should be equal the standard investment costs using a complexity factor equal to 1.0[50].

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

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

Table 13 Table of maximum and minimum Complexity Factor per group of assets

50 This information will be updated in future TYNDP when project promoters have more detail.

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

The following costs are to be considered as OPEX:

- Expected annual maintenance costs; and
- Expected annual operation costs.

These values are real values and are to be reported as an annual average figure in constant TYNDP year (e.g. 2020) euros.

It is important to highlight what cam mistakenly considered as a component of the OPEX but that actually **does not fall into this category**:

- system losses: they are taken into account in a dedicated indicator
- the cost of purchasing energy for storage investments: they are an internal variable for the SEW computation

6.16 Section 16: General Statements on Residual Impacts

As stated in Chapter 1.1, the main objective of transmission system planning is to ensure the development of an adequate transmission system which:

- 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.
- 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) wherever possible. Steps are also taken to minimise impacts through mitigation measures, and in some instances compensatory measures, such as wildlife habitat creation, 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 the total project costs (listed under indicator C1).

Since 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 internalized 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 which may not be fully mitigated in 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 either disappear if they are mitigated or compensated for or lose the status of *potential* impact (and thus 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 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). Three aspects ('biodiversity', 'landscape', and 'social integration of infrastructure'), however, could not be quantified objectively and clearly 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 of 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, since routing decisions are not taken until a later stage. In the early stages of a project it is often thus difficult to say anything concrete about the social and environmental consequences of a project, let alone determine the cost of mitigation measures to counter such effects. The quantification on these indicators will thus be presented in the form of a range, of which the 'bandwidth' tends to decrease as information increases as the project progresses in time. 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 done 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.

Once one has a global idea of the alternative routes that can be used, 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 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 social and environmental sensitivity of the project, which would not be right since the number of kilometres a line crosses through a sensitive area is only one aspect of a project's true social and environmental impact.

In 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)

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

Assessment system for residual environmental impact

- Stage: Indicate the stage of investment development. This is an important indication for the extent to which environmental impact can be measured at a particular moment.
- Basic notion: amount of km that might have to run "in" sensitive areas. An area can be sensitive to (nearby) infrastructure because of the potential effects this infrastructure will have on nature and biodiversity[51]
- Type of sensitivity: Define why this area is considered sensitive.

Example:

Investment	Stage	Impact Potentially crosses	Typology of sensitivity	Link to further information

[51] 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."

		environmentally sensitive area (nb of km)		
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 environment 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 due to 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 then ENTSO-E, in the context of the TYNDP, should notify in a dedicated space of the project sheet that, 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

Definitions:

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

Environmental impact

- Sensitivity regarding biodiversity:
  - Land protected under 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)
    - Other nature protection areas under national law

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

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 an overhead line or underground/submarine cable that 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 have to be examined on a project by project basis.

Assessment system for residual social impact

- Stage: Indicate the stage of investment development. This is an important indication for the extent to which social impact can be measured at a particular moment.
- Basic notion: # of km “in” sensitive area. An area can be sensitive to (nearby) infrastructure if it is densely populated or protected for its landscape value.
- Type of sensitivity: Define why this area is considered sensitive.

Example:

Investment	Stage	Impact Crosses dense area (nb of km)	Sensitivity Typology of sensitivity	Link to further information
A	Permitting	Yes (20 to 40km)	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 due to a social 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 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 notify in a dedicated space of the project sheet that, given that the actual route of the project might not be defined yet due to the low degree of maturity of its investmen(s), a residual social impact assessment is not yet available .

Definitions:

The following definitions provide an overview of impacts that may qualify an area as socially 'sensitive', with 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 should 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
  - Other areas protected by national law

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

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 these other impacts is the responsibility of the project promoter and they 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.

6.20 Section 20: Assessment of Storage Projects

The CBA of storage will use the same boundary conditions, parameters, overall assessment and sensitivity analysis techniques as the CBA for transmission. In particular, if the storage project does belong to the Reference Grid (depending on how and according 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 it benefits. Otherwise, if the project does not belong to the reference grid a PINT approach is applied.

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.

B1. Socio-economic welfare: The impact of storage on socio-economic welfare is the main claimed benefit of large-scale storage. 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 system. 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, by storing electricity at times when prices are low, and then offering it back to the system when the price of energy is higher, hence 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 canbe 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 in order 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 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 the table below. This assessment is to be based on the expert view considering the existing studies and technology information.

KPI	Score	Motivation
Response time – FCR[52]	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[53] 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[54] size

[52] FCR = frequency containment reserve

[53] FRR = frequency restoration reserve

[54] PTU = program time unit

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

Table 14 Qualitative Assessment of System Flexibility Benefits of Storage Project

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 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.

B10. Synchronisation with Continental Europe (for Baltic States): this indicator cannot be applied for storage projects.

B11. 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 the same way as for transmission projects as described in Reduction of Necessary Reserve for Redispatch Power Plants (B11).

C1./C2. 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 this other impacts is the responsibility of the project promoter.

6.21 Section 21: Redispatch simulations for project assessment

Assessing projects by just focusing on the impact of transfer capacities across certain international borders can lead to an underestimation of the project specific benefits 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, 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, which makes it difficult or even impossible to solely assess them by market simulations.

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

Furthermore, as also cross border projects can have an impact on internal congestions and therefore also 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 will be given below.

Overview of the process for redispatch calculations:

Generally in order to perform the project assessment under use of redispatch simulations the following simulation steps need to be performed:

1. Market simulations - determinataion of the cost optinmal power plant dispatch
2. Load-flow simulations – to get the line loadings in the observed grid
3. Redispatch simulations – to mitigate possible congestions by redispatching the initial power plant dispatch

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

General standards for redispatch simulations:

To perform redispatch simulation the same delta approach as for market simulations can be applied, i.e. the benefits are calculated under use of TOOT/PINT and multiple TOOT/PINT.

Redispatch simulations have to be aligned to the market studies conducted on the scenarios used in in the respective study. 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) have to be used as an input for the redispatch assessment.

In detail this should include the same main input dataset as to be used for market simulations:

- price assumptions (fuel prices, CO_2 price and the marginal costs of thermal generation types calculated from these)
- net generating capacities of
    - thermal generation types
    - RES: wind and solar

- Other RES, Other Non-RES
    - hydro categories (incl. pumping capacities)
- must-run values of thermal generation types
- availabilities of generation units
- DSR capacities
- demand time series
- fixed exchanges with non-modelled countries

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

- utilisation (hourly time-series) of
    - thermal generation types
    - DSR
    - 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
- ENS (energy not served) time series

Main requirements to the grid simulations:

- ideally the simulations should 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 year round basis; if this is not possible representative points in time can be used (as compared to the losses calculation)
- the method of mapping of 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 has to be consistent with other grid studies (NTC calculation, losses)

Possible resulting overloading will then be 'healed' by redispatch simulations under consideration of the following constraints:

- the balance of the system has to be kept (the rise in generation must be covered by the same amount of reduced generation)
- the network or if not possible at least pre-defined critical branches must be free of congestions after the redispatch
- the redispatch has to be done in a cost optimal way

Definition of the needed perimeter for redispatch simulations:

- The perimeter considered in the calculations should be chosen to cover all relevant grid area influenced by the project. Moreover it depends on whether the project is internal or cross-border.
    - Internal projects
        - The perimeter for internal project without significant cross-border impact is typically the country that includes the project.
    - Cross-border projects
        - The perimeter for cross-border project is typically the two countries that include the project on their common border.
- In case that only a part of the country (countries) is influenced by the project, it is possible to reduce the perimeter to this part only, on condition that the reduced perimeter includes all grid

elements relevant for the redispatch analysis, while the "relevance" has to be clearly stated and reported.

- In case that other surrounding countries are also supposed to be significantly influenced by the project, the perimeter should be extended to include these countries.

Order of optimization measures

- In principle, the following sequence must be ensured[55]:
    1. operational measures (e.g. PST, HVDC)
    2. Pre-defined set of topological curative actions for each N-1 (or respective security criterion)
    3. Thermal Power plants based on the dispatch costs of each generator
    4. Storages (Hydro, Batteries, P2G)
    5. RES
    6. Cross Border Power plants and Cross Border HVDC's (depending on the perimeter)
    7. Overloading

As for different project types with different objectives also the simulation methods can be different, dependent on the respective targets: while cross border project per definition will have a major impact on increasing the capacity between different countries and market areas, for internal projects a cross-border impact might not be the main aim of the project. Hence, for these kinds of projects it would make only little sense to assess it by the comparison of two different market simulation runs only.
Therefore the two options for projects for applying redispatch simulations will be given below: option one solely uses redispatch simulations[56] to calculate the benefits while option two integrates both market and redispatch modelling.
The decision which methodology to apply needs to be taken for each project case specific: in general it can be said that for assessing the market benefits of a project, pure market simulations should be used in case the main aim of the project relies on a cross border level. While for projects having the main focus in healing internal congestions, pure redispatch simulations should be used. Of course there are also projects that are built to fulfill 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 what method to use is upon the project promoter. However, in the end the chosen method needs to be displayed together with a justification of the respective choice. In case of the assessment using a combination of market and redispatch studies, the benefits have to be displayed separately for market- and redispatch studies.

The indicators that can be calculated by use of redispatch simulations are those as defined under the respective indicator.

Note:

[55] No country specific differences to this approach have yet been identified. If these are identified, they must be taken into account.
[56] The basis for the redispatch simulation under this option of course 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 amount of redispatch needed with and without the project (in the grid model) makes the basis of the assessment.

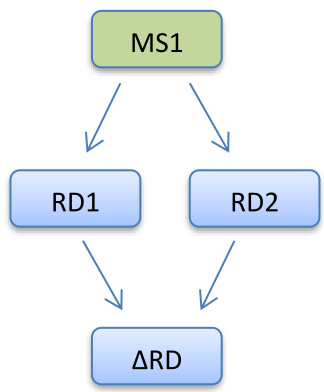
The following options are just related to the benefit calculation itself, in order to be able to perform redispatch simulations preceding market and network simulations are always necessary.

1.1.1.1 BENEFITS FROM PURE REDISPATCH

The benefits for projects with a focus mainly on internal impacts can solely be assessed by use of redispatch simulations.

Guideline:

Based on the single market simulation output two different redispatch simulations, one with the project, the other without the project, need to be performed (TOOT/PINT) respecting the conditions defined in the Section above.

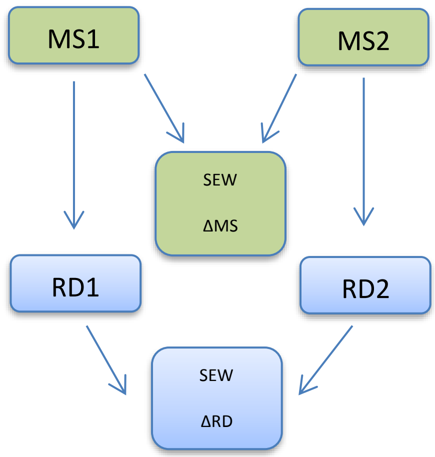


MS1: market simulation reference NTCs
RD1: redispatch run with reference network
RD2: redispatch run with the project being assessed taken out/in (TOOT/PINT)
ΔRD: difference between RD1 and RD2 unit commitment (different generation costs, different CO_2 output etc.)

1.1.1.2 BENEFITS FROM A COMBINATION OF BORDER-NTC-VARIATION AND REDISPATCH

The benefits of some projects are mainly depending on internal bottlenecks, but also can have significant cross-border impact.

Guideline:
In this case a two-step approach can be used by combining the assessment using market simulations with redispatch simulations while the final result is the sum of both.



MS1: market simulation with reference network
MS2: market simulation with the project being assessed taken out/in (TOOT/PINT)
ΔMS: difference between MS1 and MS2 unit commitment
RD1: redispatch run with reference network
RD2: redispatch run with the project being assessed taken out/in (TOOT/PINT)
ΔRD: difference between RD1 and RD2 unit commitment
ΔTOTAL = ΔRD + ΔMS

1.1.1.3 Reduction of Necessary Reserve for Redispatch Power Plants (B11)

This benefit indicator can only be calculated when applying redispatch simulations for the project assessment and has to be added to the set of benefit indicators as described under B1 – B8.

Introduction

The redispatch changes the cost-optimal dispatch by exchanging cheaper by more expensive units. This leads to situations where more peaking units are running. In some countries, already today, the respective power plants for covering this maximum needed redispatch capacity are ensured by specific contracts.

Therefore the maximum redispatch power is a direct indication for the need of reserve power plants and the difference (with and without the project) gives a direct indication of the change in needed reserve power plants.

Methodology

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

The capacity of necessary reserves for redispatch (in MW) can be achieved 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.

Monetisation

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

Example

Within this fictitious example the B11 indicator for an internal project in country A will be calculated. It is assumed that within country A a respective mechanism for allocating redispatch power plantes exists and that the assessment has been performed using redispatch simulations. The project is part of the reference grid and thus the TOOT method will be applied.

1. Calculating the redispatch power with and without the porject for each hour of the year
2. Finding the maximum redispatch power for both cases (with and without the project)

   RD_{power}(with) = 16000 MW, which appear ins hour 3465

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

3. Building the delta

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

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

   B11 = 2000 MW * 20k€/MW = 40 M€

Double-counting

As this benefit indicator can only be applied to projects located in countries where a specific mechanism for allocating redispatch power plants exists and that in reality the costs for allocating them have to be payed independently if the respective capacity will be used or not, the risk of double accounting is not given. Furthermore, even when these redispatch reserves are needed payments, the allocation payments and the actual redispatch costs, have to be taken. While within the simulations only the latter part is taken into account the reduction of allocation payments need to be added to the overall project benefit.

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

Table 15 Reporting Sheet of this Indicator in the TYNDP

6.22 Section 22: Example of ΔNTC Calculation

This illustration delivers an example on how to calculate the ΔNTC using the TOOT approach for one time step (PINT approach is similar, only the position of the project towards the reference network model changes); see also Table 16. The following example is designed for a ΔNTC calculation across any boundary between bidding zones[57]. This methodology should be performed over all the time step of the year in order to get an annual (or some seasonal) delta NTC to be used for simulations.

Consider the example system as presented in Figure 10 below.

1. Perform load flow analysis on the reference network model in line with the security criteria that take into account the N-1 criteria
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[58] in the zones X and Y (and vice versa)[59].
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.
4. Calculate the ΔNTC as the difference between the generation situations that correspond with the 100%-situations: ΔNTC equals the power shift.
5. Apply this process to both directions of power flow across the boundary under analysis.

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

[58] 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 to 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 reach the 100% and find the corresponding power value. Depending on the initial conditions, this power shift would increase or reduce the reference power flow.

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

Simplified example of NTC increase from direction X to Y across a boundary

	Step 1	Step 2	Step 3	Step 4
Incident	Line B in	Line B in	TOOT line B	TOOT line B
Situation	initial situation	100% situation	>100% situation	mitigated situation thus back to 100%
Generation in zone X	400	900	900	600
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%	-	-

Step 5
Δ NTC X > Y [MW]
300

Table 16 *Example of how to calculate the ΔNTC: 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% (here line A) 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 compared to Step 2 to reduce 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 X>Y across the boundary.*

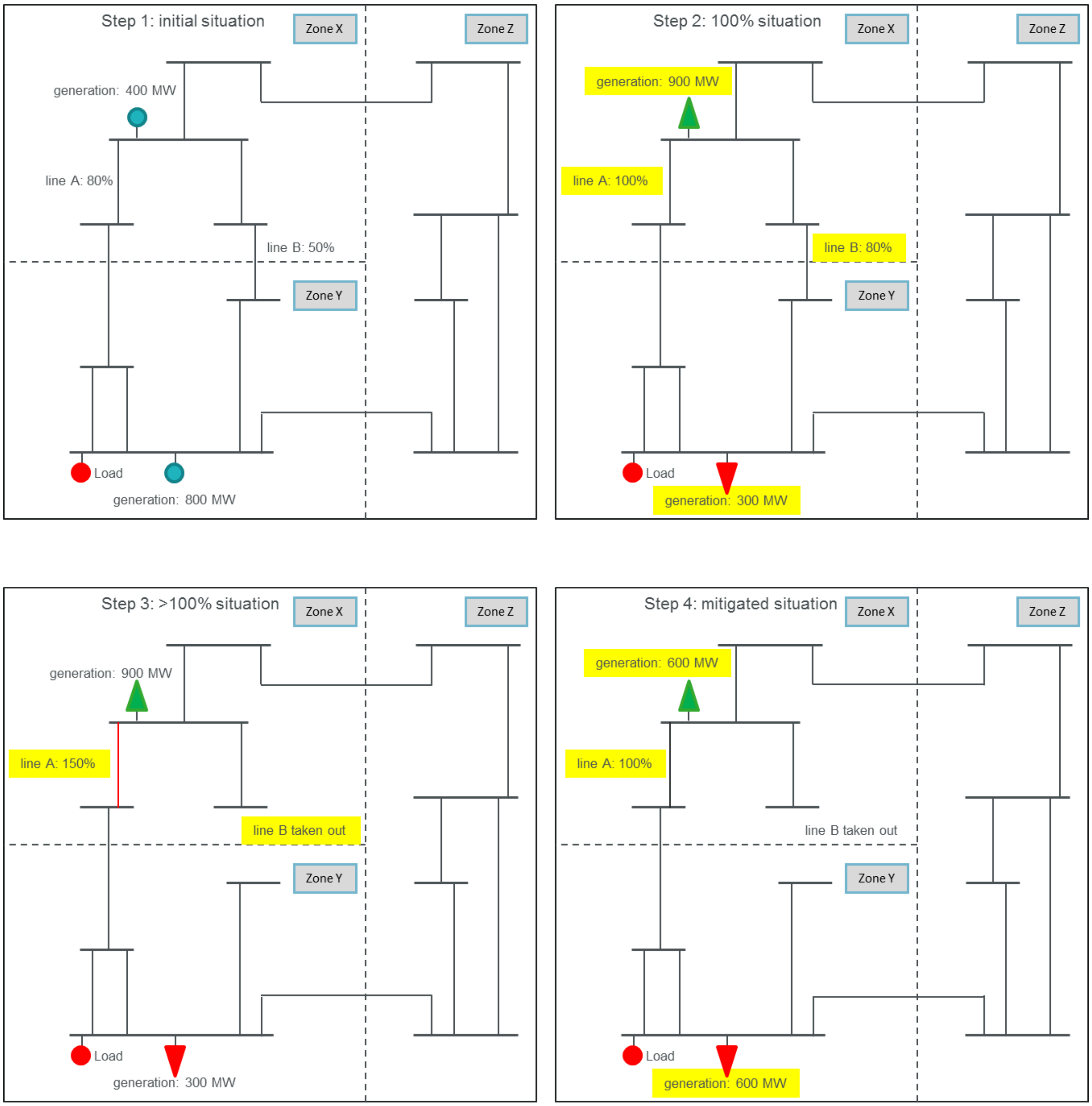


Figure 10: Qualitative example to illustrate the single steps as described in the example above. It should be noted that the real physical flow will also have a component across the boundary between the zones X-Z as well as Z-Y.

6.23 Section 23: Impact on Market Power

Context

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. This paper analyses this indicator and its limits, as well as the necessary methodology to construct it.

Basics on methodology

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 carefully which asset(s) will be assessed. The calculation of the index will be made with and without this object, and the difference on 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.

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

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.

Limits of market power indicators

First, it must be highlighted that the calculation of all these indexes requires confidential data as input. Thus, a balance has to 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. The results of a CBA in terms of market power can therefore 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, for example 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 heavily 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 other, faster ways to solve market power issues, through regulation for example. 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 on this aspect. Taking market power into account in a CBA can thus lead to sub-optimal decisions.

Conclusion

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. National markets have already begun to merge, through market coupling, and a reporting of benefits on market power by Member States is already outdated.

6.24 Section 24: Multi-Criteria Analysis and Cost Benefit Analysis

Goals of any project assessment method

- *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 Region-al Group).

The limits of a fully monetised cost benefit analysis

A fully monetised CBA cannot cover all criteria specified in Annexes IV and V of the Regulation (EU) No 347/2013, since 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.

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."

This is why 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.

6.25 Section 25: Value of Lost Load

The Value of Lost Load (VOLL) is a measure of the costs associated with unserved energy (the energy that would have been supplied if there had been no outage) for consumers. It 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, since there is presently no market for security of supply.

The value for VOLL that is used during project assessment should reflect the real cost of outages for system users, hence providing an accurate basis for investment decisions. A level of VOLL that is too high would lead to over-investment, a value that is too low would lead to an inadequate security of supply because the cost 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 should lead to striking the right balance 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 by geographic factors, differences in the nature of load composition, the type of affected consumers, and the level of dependency on electricity in the geographical area impacted, differences in reliability standards, the time of year and the duration of the outage. Using a general uniform estimation for VOLL would lead to less transparency and inconsistency, and 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.

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

The table below 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, nor does ENTSO-E endorse any of the values shown below.

Country	VOLL (€/kWh)	Date	Used in planning ?	Method/reference	Reference
Austria (E control)	WTP: Industry 13,2, Households, 5,3 Direct worth: Households: 73,5 Industry : 203,93	2009	No	R&D for incentive regulation, Surveys using both WTP and Direct Worth	(4)
France (RTE)	26. Sectoral values for large industry, small industry, service sector, infrastructures, households & agriculture available	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 Industry : 8 Mean : 40	2005	No	R&D, production function approach	(6)
Italy (AEEG)	10,8 (Households) 21,6 (Business)[60] 20 to 40 (according parameters)[61]	2003/2017	No	Surveys for incentive regulation, using both WTP and Direct Worth (SINTEF)	(3) & (5)
Netherlands (Tennet)	Housholds 16,4 Industry : 6,0 Mean : 8,6	2003	No	R&D, production function approach	(7)
Norway (NVE)	Industry: 10,4 Service sector: 15,4 Agriculture: 2,2 Public sector: 2 Large industry: 2,1	2008	Yes (sectorial values)	Surveys for incentive regulation, using both WTP and Direct Worth (SINTEF)	(9) and (10)
Portugal (ERSE)	1,5	2011	Yes (mean value)	Portuguese Tariff Code	(14)
Spain	6,35	2008	No	R&D, production function approach	(8)
Sweden	Households 0,2 Agriculture 0,9 Public sector 26,6 Service sector 19,8 Industry 7,1	2006	No	R&D, WTP, conjoint analysis	(11)

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

References:

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

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

61 National Network Code Annex 74 and Attachement to the National Development Plan (pag 76)

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

3) "The use of customer outage cost surveys in policy decision-making: the italian experience in regulating quality of electricity supply", A. BERTAZZI and L. LO SCHIAVO

4) « Economic Valuation of Electrical Service Reliability in Austria – A Choice Experiment Approach », Markus Bliem, IHSK, 2009

5) « 5th CEER Benchmarking Report on the Quality of Electricity Supply », 2011

6) « Security of Supply in Ireland », Sustainable Energy Ireland, 2007

7) "The value of security of supply", Nooij/Koopmans/Bijvoet, SEO, 2005

8) « The costs of electricity interruptions in Spain. Are we sending the right signals? », Pedro Linares, Luis Rey, Alcoa Foundation, 2012

9) FASIT, KILE-satser, 2011

10) « Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results, G. Kjölle" (SINTEF) IEEE TRANSACTIONS ON POWER SYSTEMS, 2008

11) « Kostnader av elavbrott: En studie av svenska elkunder ». Carlsson, Fredrik & Martinsson, Peter, Elforsk rapport nr 06:15, (2006),

12) "Quelle valeur attribuer à la qualité de l'électricité" ? RTE, 2011

13) Desktop review and analysis of information on Value of Lost Load for RIIO-ED1 and associated work, Reckon, May 2012

14) ERSE, PARÂMETROS DE REGULAÇÃO PARA O PERÍODO 2012 A 2014 – Dezembro 2011

Providing a reliable figure for VOLL, which reflects the actual societal costs of an outage, is vital for a proper project assessment with a monetized EENS-component. Once EENS is monetized, 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 monetized value is simply included in the summation of all monetized benefits and costs (e.g., to obtain a simple cost-benefit ratio). This is not problematic if an appropriate set of VOLL-values exists, which properly takes into the account the spatial, temporal, and actual characteristics that are 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 standardized project assessment results is undermined. ENTSO-E therefore strongly discourages the use of the values reported in the table above 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 monetized values of EENS.

The CEER has set out European guidelines[62] for nationwide studies on 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 establishing 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 standardized methodology to compute values for VOLL, EENS can nonetheless be monetized 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 of each project, allows all interested parties to monetise by using the preferred VOLL available.

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 practice and further editions of the TYNDP document of ENTSO-E.

[62] 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