ENTSO-E

Guideline for Cost Benefit Analysis of Grid Development Projects

September 2012

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1.1. Transmission system planning

The move to a more diverse power generation portfolio due to the rapid development of renewable energy sources and the liberalization of the European electricity market has resulted in more and more interdependent power flows across Europe, with large and correlated variations. Therefore, transmission system design must look beyond traditional (often national) TSO boundaries, and move towards regional and European solutions. Close co-operation of ENTSO-E member companies responsible for the future development of the European transmission system is required to achieve coherent and coordinated planning that is necessary for such solutions to materialize.

The main objective of transmission system planning is to ensure the development of an adequate transmission system which, with respect to mid and long term time horizons:

- Enables safe system 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 harmonization;
- Contributes to energy efficiency of the system.

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

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

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

Furthermore, the draft regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure (2011/0300 (COD) 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” (Art. 12).

This document constitutes an update of ENTSO-E’s Guidelines for Grid Development, aiming at compliance with the requirements of the draft Regulation, and ensuring a common framework for multi-criteria cost benefit analysis for candidate projects of common interest (PCI) and other projects falling within the scope below.

1.2. Scope of the document

This document describes the common principles and procedures to be used when performing combined multi-criteria and cost benefit analysis in view of elaborating Regional Investment Plans and the Community-wide Ten Year Network Development Plan (TYNDP), as ratified by EU Regulation 714/2009 of the 3rd Legislative Package. It will also serve for assessing Projects of Common Interest (PCI) as established by Art. 12 of the draft Regulation.

Typically, three categories of development transmission projects can be distinguished:

- Those that only affect transfer capabilities between individual TSOs. These projects will be evaluated according to the criteria in this document.
- Those that affect both transfer capabilities between TSOs and the internal capability of one or more TSOs' network. These projects will meet the criteria of this document and of the affected TSOs' internal standards.
- Those that only affect an internal national network and do not influence interconnection capability. These do not fall within the scope of this code, and are developed according to the TSO's internal standard.

The CBA guideline sets out ENTSO-E's criteria for assessments of costs and benefits of a transmission project, all stemming from European policies of market integration, security of supply and sustainability. It describes the approach both for clustering of projects and for measuring each of the indicators. In order to ensure a full assessment of all transmission benefits, some are monetized, while others are measured through physical units such as tons or kWh. This set of common European-wide indicators will form a complete and solid basis, both for project evaluation within the TYNDP, and coherent project portfolio development for the PCI selection process.

Figure 3: Scope of cost benefit analysis

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. This document describes each phase of the development planning process as well as the planning criteria and methodology adopted by ENTSO-E.

The first phase of the planning process consists of the definition of scenarios, which represent a coherent, comprehensive and internally consistent description of a plausible future. The aim of scenario analysis is to depict uncertainties on future system developments on both the production and demand sides. In order to incorporate these uncertainties in the planning process, a number of planning cases are built, taking into account forecasted future demand level and location, dispatch and location of generating units, power exchange patterns, as well as planned transmission assets. This phase is detailed in Chapter 2.

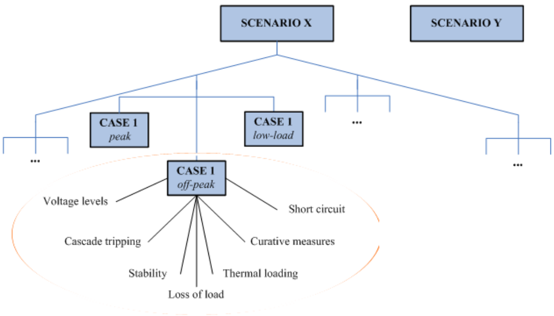


Figure 1: Scenarios and planning cases

Chapter 3 describes the multi-criteria cost-benefit analysis framework adopted for project assessment, complying with the Regulation on guidelines for trans-European energy infrastructure.

The cost benefit impact assessment criteria adopted in this document reflect each transmission 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), RES integration 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 internalized within other benefits, such as CO2 avoidance and renewable energy integration via socio-economic welfare, while others remain completely non-monetized, such as security of supply.

"Network stress tests" are thus performed on each planning case and follow specific technical planning criteria developed by ENTSO-E on the basis of long term engineering practice. The criteria cover both the kind of contingencies[1] chosen as "proxies" for hundreds of other events that could happen to the grid, and the adequacy criteria relevant for assessing overall behavior of the transmission system. The behavior of the grid when simulating the contingencies indicates the "health" and robustness of the system. A power system that fails one of these tests is considered "unhealthy" and steps must be taken so that the system will respond successfully under the tested conditions. Several planning cases are thus assessed in order to identify how robust the various reinforcements are. This process is developed in Chapter 4.

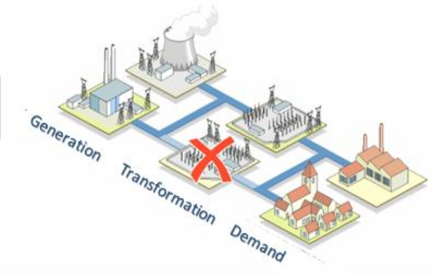


Figure 2: N-1 principle

[1] A contingency is the loss of one or several elements of the power transmission system

The whole process is continually evolving, so it is the intention that this document is reviewed periodically in line with prudent planning practice and further editions of the TYNDP, as foreseen by Article 6 of the draft Regulation.

2. SCENARIOS AND PLANNING CASES

Planning scenarios are defined to represent future developments of the energy system. The essence of scenario analysis is to come up with plausible pictures of the future. Scenarios are means to approach the uncertainties and the interaction between these uncertainties. Planning cases represent the scenarios.

> Multi-criteria cost benefit analysis of candidate projects of European interest is based on ENTSO-E's System Outlook and Adequacy Forecast (SO&AF), which 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 the generation mix. The scenarios are elaborated after formally consulting Member States and the organisations representing all relevant stakeholders

2.1. Scope of scenarios

Scenarios shall at least represent the Union's electricity system level and be adapted in more detail at a regional level. They shall reflect European Union and national legislations in force at the date of analysis.

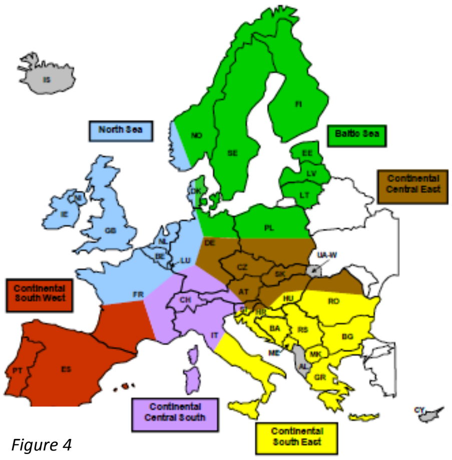


Figure 4

Structure of the ENTSO-E regions, contributing areas and control areas

2.2. Content of scenarios

Planning scenarios are a coherent, comprehensive and internally consistent description of a plausible future (in general composed of several **time horizons**) built on the imagined interaction of **economic key parameters** (including economic growth, fuel prices, CO2 prices, etc.). A planning scenario is characterized by a **generation portfolio** (power installation forecast, type of generation, etc.), a **demand forecast** (impact of efficiency measures, rate of growth, shape of demand curve, etc.), and **exchange patterns** with the systems outside the studied region. A scenario may be based on trends and/or local specificities (bottom-up scenarios) or energy policy targets and/or global optimization (top-down scenarios).

As it can take more than 10 years to build new transmission infrastructure, the objective is to construct scenarios that look beyond the coming 10 years. However, when looking so far ahead, it becomes increasingly difficult to define what a 'plausible' scenario entails. Therefore, the objective of the scenarios is to construct contrasting future developments that differ enough from each other to capture a realistic range of possible future pathways that result in different challenges for the grid.

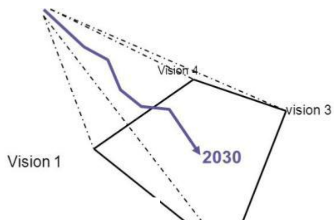


Figure 5: ENTSO-E visions

2.2.1 Time horizons.

The scenarios will be representative of at least two time horizons based on the following:

- Long-term horizon (typically 10 to 20 years). Long-term analyses will be systematically assessed and should be based on common ENTSO-E scenarios.
- Mid-term horizon (typically 5 to 10 years). Mid-term analyses should be based on a forecast for this time horizon. ENTSO-E's Regional groups and project promoters will have to consider whether a new analysis has to be made or analysis from last TYNDP (i.e. former long term analysis) can be re-used.
- Very long-term horizon (typically 30 to 40 years). Analysis or qualitative considerations could be based on the ENTSO-E 2050-reports.
- Horizons which are not covered by separate data sets will be described through interpolation techniques.

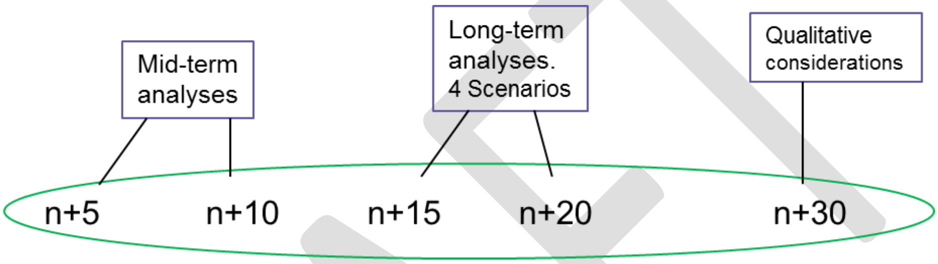


Figure 6: Time Horizons

The scenarios developed in a long-term perspective may be used as a bridge between mid-term horizon and very long term horizons (+30 or 40). The aim of the n+20 perspective should be that the pathway realized in the future falls within the range described by the scenarios with a high level of certainty.

2.2.2 Bottom-up and Top-down approach

Until the preparation of the TYNDP 2010, the classic way of constructing generation and load scenarios within ENTSO-E (for the identification of grid investment needs) was mainly based on a bottom-up approach. Load and generation prognoses were collected from each TSO and mathematically summarized. Hence, the basis of the analysis was more or less national.

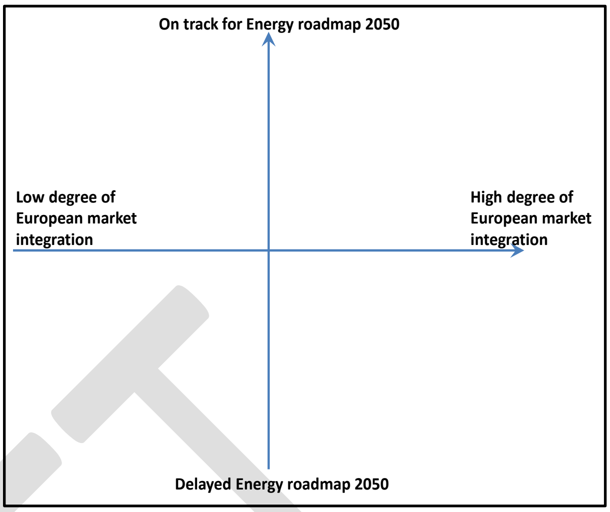
A new methodology was introduced by ENTSO-E in the TYNDP 2012. An EU 2020 scenario was constructed using a top-down approach, in which the load and generation evolution was constructed for all countries in a way that was compliant and coherent with the same macro-economic and political view of the future. For the EU 2020 scenario this meant that the forecasted load and generation assumptions had to be coherent with the EU 3x20 targets. Therefore, the load and RES generation in the EU 2020 scenario was derived from the NREAPs for EU countries. The top-down approach thus uses a common European basis.

Summarized, the scenarios used in cost-benefit analyses could be both top-down and bottom-up. One top-down scenario should be defined as the reference scenario. This scenario should be the one that best reflects the official European energy politics and goals. Thus, except when explicitly indicated, all key parameters listed below will be coherent at a European level with the economic background provided by the reference scenario.

'Zoom ENTSO-E: 2030 Visions for TYNDP 2012

For the coming TYNDP, the scenarios are developed around axes describing implementation of renewables and describing market integration.

The first axis (Y-axis) is related to the EU commitment to reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050, according to the **Energy roadmap 2050**. The objective is not to question this commitment but to check the impact of a delay in the realization of this commitment on grid development needs by 2030. The two selected outcomes are viewed to be extreme enough to result in very different flow patterns on the grid. The first selected outcome is a state where Europe is **on track** to realize the set objective of energy decarbonization by 2050. The second selected outcome is a state where Europe faces a **serious delay** in the realization of the energy 2020 goals and likely delays on the route to decarbonization by 2050.



The second axis (X-axis) relates to the degree of **European market integration**. This can be done in a **strong European framework or a context of a high degree of European integration** in which national policies will be more effective, but not preventing Member States developing the options which are most appropriate to their circumstances, or in a **loose European framework or a context of a low degree of European integration** that lack a common European scenario for the future energy system that results in parallel national schemes. The strong European framework should also include a well-functioning and integrated electricity market, where competition ensures efficient dispatch at the lowest possible costs on a European level. On the other hand, a loose European framework results in less market integration and poor cross-border competition.

2.2.3 Reference and sensitivity scenarios

Regarding analyses of different scenarios, there will always be a compromise between quality (driver for analyzing a large number of scenarios) and workload (driver for reducing the number of scenarios analyzed).

Cost-benefit-analyses should be analyzed for at least two scenarios.

<u>Reference scenarios</u>

Primary analyses should be done on a common ENTSO-E reference scenario, which should be the scenario that best reflects the official European energy politics and goals. This means that a top-down scenario is most relevant as top-down scenarios better reflect one harmonized European energy policy.

At least one other scenario should be analyzed, for instance in order to take into account regional differences or to ensure robustness to different evolutions of the system. In case this scenario is not consistent with common ENTSO-E scenarios, the differences should be explained.

<u>Sensitivity scenarios</u>

Secondary and optional analyses could be done on the other long-term scenarios. If these scenarios are not fully analyzed, their effect on the different projects should be qualitatively considered. The other scenarios used for sensitivity analysis can be top-down scenarios or bottom-up.

2.3. Technical and economic key parameters

Economic key parameters

Fuel costs will be based on reference values established by international institutes such as the IEA, if possible at the study horizon taken into account. The economic key parameters include, but are not limited to, the following list:

Economic parameter	Level of coherence
Economic growth	European
Coal cost	
Oil cost	
Gas cost	
Lignite cost	
Nuclear cost	
CO2 cost	
Biomass cost	

Technical key parameters

Technical key parameters include, but are not limited to, the following list:

Technical parameter	Level of coherence
Efficiency rate	New plants : European Old plants : National
Availability	European
CO2 emission rate	European
Reserve power	European
Must-run units	European
Share of non dispatchable generation	European

Scenarios for generation

Scenarios for generation will include generation capacities (assumptions on existing and new capacities as well as decommissioning), efficiency rate, flexiblity, must-run obligations and location (market) of at least the following generation types:

Generation capacity	Level of coherence
Biomass	European
Coal	
Gas	
Oil	
Lignite	
Nuclear	
Wind	
Photovoltaic	
Geothermal	
Concentrated solar	
Marine energies	
CHP	
Hydro	
Storage	
Capacity equipped for capturing carbon dioxide	

Scenarios for demand

Scenarios for demand will take into account at least the following items:

Demand factors	Level of coherence
Economic growth	European
Evolution of demand per sector	
Load management	
Sensitivity to temperature	
Fuel shift	
Evolution of climate-related extreme weather events[2]	
Evolution of population	National

Exchange patterns[3]

Exchange patterns outside the modeled area will be taken into account in the following way:

Exhange pattern	Level of coherence
Fixed flows between the region and the outside countries	European

2.4. From scenarios to planning cases

The identification of the grid development needs related to a particular scenario is a complex resource and time-consuming process. The output of market analysis (generation dispatch, power and energy balances, periods of constraint) is used as an input for load flow analysis to choose the most representative planning cases (points in time) to be studied. The results are compared and the transmission adequacy is further measured allowing the iterative process of identifying the required reinforcement projects for supporting the bulk flow patterns identified in the market study.

Thus, this is not a unidirectional process, but a process with several feedback loops that could change assumptions (such as reserve, flexibility and sustainability of generation). Hence, it is important to keep the number of scenarios and cases that are fully calculated and therefore need to be quantified, limited, and to assess the impact of possible different pathways through sensitivity analysis.

The use of these scenarios for long-term grid development will lead to the identification of new flexible infrastructure development needs that are able to cope with a range of possible future energy challenges outlined in the scenarios.

2.4.1 Selection of planning cases

Market based assessment aims to perform an economic optimization of the generation dispatch in each node of an interconnected system, for every hour of the year, using a simplified representation of the grid. This may be a DC load flow approximation with a small number of nodes and branches, or be as simple as one node per area and one branch across each boundary (all generation and load data are aggregated to this single node). This approach assumes that there are no internal constraints within a country/region, and limited grid transfer capability (GTC[4]) between them, generally without impedance description. Market studies have the advantage of clearly highlighting the structural rather than incidental bottlenecks. They take into account several constraints such as

[2] Annex 4, 2c

[3] All off shore wind farm generation is allocated to a Member state, and hence, flows between countries are not variable depending on allocations of off shore wind farms.

[4] GTC is not only set by the transmission capacities of cross-border lines but also by the ratings of so-called “critical” domestic components (see 3.3)

flexibility and availability of thermal units, hydro conditions, wind and solar profiles, load profile and uncertainties.

Network analysis, on the other hand, uses a simplified representation of generation and demand profiles, but includes a detailed representation of the grid. Planning cases for network analysis[5] are selected i.e. based on the following considerations:

- outputs from market studies, such as system dispatch, frequency and gravity of constraints;
- regional considerations, such as wind and solar profiles or cold/heat spell;
- (when available,) results of pan-European power transfer distribution factor (PTDF[6]) analysis.

Network studies have the advantage of taking into account internal congestion on the network (including loop flows). They contribute to assessing the GTC and its increase enabled by transmission projects. This output of the network studies can be retrofitted in market studies to assess the improvements brought by the enhanced grid.

Market studies and network studies are thus complementary. They are articulated in a two-step, iterative process in order to ensure consistency and efficiency (every concern being properly addressed with the appropriate modeling). An iteration of both methods is therefore recommended.

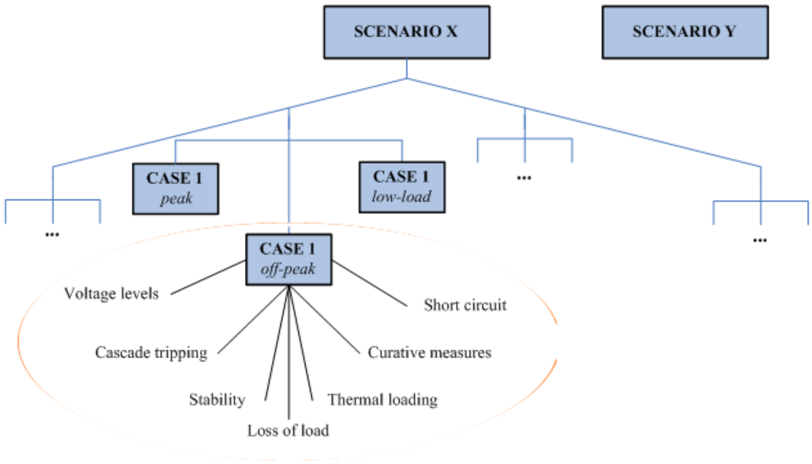


Figure 7: Scenarios and planning cases

2.4.2 Scope of planning cases

Each selected scenario is assessed by analyzing the cases that represent it. These cases are defined by the TSOs involved in each study, taking into account regional and national particularities.

The following are the more important issues that have to be taken into account when building detailed cases for planning studies:

Demand, generation and power exchange forecasts in different time horizons, and specific sets of network facilities are to be considered.
Demand and generation fluctuate during the day and throughout the year.

[5] Ideally, all 8760 hours should be assessed in a load flow. However, no tool is able to perform this in an efficient way on a wide perimeter today.

[6] The PTDF analysis show the linear impact of a power transfer. It represents the relative change in the power flow on a particular line due to an injection and withdrawal of power.

Weather is a factor that not only influences demand and (increasingly) generation, but also the technical capabilities of the transmission network.

2.4.3 Content of a planning case

A planning case represents a particular situation that may occur within the framework specified by a scenario, featuring:

- One specific point-in-time (e.g. winter / summer, peak hours / low demand conditions, year), with its corresponding demand and environmental conditions;
- A particular realization of random phenomena, generally linked to climatic conditions (such as wind conditions, hydro inflows, temperature, etc.) or availability of plants (forced and planned);
- The corresponding dispatch (coming from a market simulator or a merit order) of all generating units (and international flows);
- Detailed location of generation and demand;
- Power exchange forecasts with regions neighboring the studied region;
- Assumption on grid development.

When building representative planning cases, the following issues should be considered taking into account the results from market analysis:

- Estimated main power exchanges with external systems.
- Seasonal variation (e.g. winter/summer).
- Demand variation (e.g. peak/valley).
- Weather variation (e.g. wind, temperature, precipitations, sun, tides).

All transmission assets that are included in existing mid-term plans[7] will be dealt with in the corresponding case taking into account the forecasted commissioning and decommissioning dates.

The uncertainty in the commissioning date of some future assets could nevertheless require a conservative approach when building the planning cases, taking into account:

- State of permitting procedure (permits already obtained and permits that are pending).
- Existence of local objection to the construction of the infrastructure.
- Manufacturing and construction deadlines.

A case without one or some reinforcements foreseen, as well as cases including less conservative approaches, could be analyzed.

To check the actual role of a grid element, and thus compare different strategies (e.g. refurbishment of the asset vs. dismantling and building a new asset), it may be considered as absent in the planning case.

2.5. Multi-case analysis

System planning studies are often based on deterministic analysis, in which several representative planning cases are taken into account. Additionally, studies based on a probabilistic approach may be carried out. This approach aims to assess the likelihood of risks of grid operation throughout the year

[7] All new projects for which a final investment decision has been taken and that are due to be commissioned by the end of year n+5 (Annex V, point 1a)

and to determine the uncertainties that characterize it. The objective is to cover many transmission system states throughout the year taking into account many cases. Thus it is possible to:

- Detect 'critical system states' that are not detected by other means.
- Estimate the probability of occurrence of each case that is assessed, facilitating the priority evaluation of the needed new assets.

The basic idea of probabilistic methods is based on creating multiple cases depending on the variation of certain variables (that are uncertain). Many uncertainties can lead to building multiple cases: demand, generation availability, renewable production, exchange patterns, availability of network components, etc. The general method consists of the following steps:

1. Definition of variables to be considered (for example: demand).
2. Definition of values to be considered for each of the variables and estimation of the probability of occurrence. In case a variable with many possible values is considered (for example: network unavailability), the amount of different possible combinations could justify the use of a random approach method.
3. Building the required planning cases. The number of cases depends on the number of variables and the number of different values for each of these.
4. Each case is analyzed separately.
5. Assessment of the results. Depending on the amount of cases, a probabilistic approach could be needed to assess the results. A priority list of actions could result from this assessment.

If the variables used to build multiple cases are estimated in a pure probabilistic way, a statistical tool is needed for the assessment. In this case, besides helping to make a priority list of the actions needed in a development plan and identifying critical cases not known to be critical in advance, the probabilistic approach allows forecasting the Expected Energy Not Supplied (EENS) and Loss Of Load Expectation (LOLE) and congestion costs. The probabilistic assessment of other variables, like short-circuit current, could also be very useful for planning decisions.

3. Project Assessment: combined cost benefit and multi-criteria analysis

The goal of project assessment is to characterize 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.

The present chapter establishes an operative methodology for project identification and for characterization of the impact of individual investments or "projects" (clusters of candidate investments[8]), falling into the scope described below.

The methodology will be used both for common project appraisals carried out for the TYNDP and for individual project appraisals undertaken by TSOs or project promoters.

3.1. Project identification

If transmission weaknesses are identified and the standards described in chapter 4 are not met, then reinforcement of the grid is planned. These measures can include, but are not limited to, the following:

- Reinforcement of overhead circuits to increase their capacity (e.g. increased distance to ground, replacement of circuits).
- Duplication of cables to increase rating.
- Replacement of network equipment or reinforcement of substations (e.g. based on short-circuit rating).
- Extension and construction of substations.
- Installation of reactive-power compensation equipment (e.g. capacitor banks).
- Addition of network equipment to control the active power flow (e.g. phase shifter, series compensation devices).
- Additional transformer capacities.
- Construction of new circuits (overhead and cable), DC or AC.

For the avoidance of doubt, the following varieties of solution to transmission weaknesses are not expected to be appraised by these Guidelines – i.e. they are out-of-scope:

- Relocation of Generation: the location of generation, as set out in planning cases, is a given[9]
- Assumption of new demand-side services: demand-side services are not considered as solutions to transmission weaknesses, since existing and future volume of demand-side service, whereby demand adjusts its consumption in response to transmission weakness, is modeled within background scenarios consulted upon with stakeholders.
- Electricity Storage: as present, electricity storage devices (whether pumped storage, batteries, or other) are not included as solutions to transmission weaknesses, since a different methodology is needed for assessment of storage solutions.
- Generator Inter-trips: in this context, the treatment of system-to-generator inter-trips is ambivalent. On the one hand, system-to-generator inter-trips are recommended to mitigate emergency situations like out-of-range contingencies[10]. On the other hand, system-to-generator inter-trips are not normally proposed by most TSOs as primary solutions to transmission

[8] For more details about clustering of projects, see chapter 3.2.

[9] TSOs, while having a role in informing the market and public authorities about system weaknesses, cannot choose to relocate or build generation.

[10] ENTSO-E : Technical background and recommendations for defense plans in the Continental Europe synchronous area (https://www.entsoe.eu/resources/publications/system-operations/)

weaknesses, and should not be regarded as a structural measure to cope with transmission weaknesses and cannot substitute any grid reinforcement.

3.2. Clustering of projects

A project is defined as a cluster of investment items that have to be realized in total to achieve a desired effect. Therefore, a project consists of one or a set of various investments. An investment should be included only if the project without this investment does not achieve the desired effect.

The clustering of a group of investments is recommended by EC[11] when:

They are located in the same area or along the same transport corridor;
They achieve a common measurable goal;
They belong to a general plan for that area or corridor;
Basically, a group of investments should be clustered if the investments (lines, substations …) comply with the conditions recommended by EC:

1. They achieve a common measurable goal. For instance, they are required to develop the grid transfer capability (GTC) increase associated with the project (see 3.3).
2. They are located in the same area of the project or along the same transmission corridor, and they belong to a general plan for that area or corridor.

The first condition derives from the goal of project assessment through the benefit categories set out in chapter 3.3. In fact, the assessment of main benefits is directly related to the evaluation of the increase of GTC associated with the project: security of supply, socio-economic welfare, RES integration and variation of CO2 emissions.

> The influence of the investment on the increase of GTC must be substantial; otherwise it should not be a part of the cluster. Hence, if the influence is lower than 20%, the investment will not be considered as a part of the project.

The calculation is done in the following way (using the TOOT or PINT method as specified in section 3.6.4):

First of all, the calculation of the GTC increase provided by the main investment (1) (such as an interconnector) is made obtaining ΔGTC_1. Then, taking into account the scenarios which include investment 1, a new investment (2) (such as an internal transmission line) is added, obtaining ΔGTC_2. <u>If $\Delta GTC_2 > 0.20\ \Delta GTC_1$</u>, investment 2 can be clustered. Then, taking into account the scenarios with investment 1 included, a new investment (3) is added and ΔGTC_3 is obtained. If $\Delta GTC_3 > 0.20\ \Delta GTC_1$ investment 3 can be clustered. The process ends when all candidate investments have been analyzed.

[11] European Commission. Guide to Cost-Benefit analysis of investment projects, July 2008., p. 20

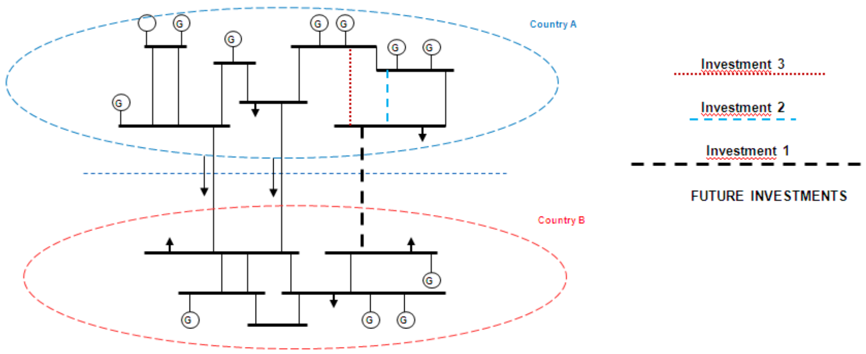


Figure 8: Clustering of investments

It is possible for a project to be limited to a single investment item only. An investment item can also contribute to two projects whose drivers are different, in which case its cost should only be counted in the main project.

Specific cases:

Two or more projects can be a clustered, if they are in series and/or almost completely dependent on each other. Indeed two such projects should be clustered, if the GTC increase on commissioning either project individually is less than 50% of the GTC increase on commissioning both projects together.

- An example of projects completely dependent on each other (one is a precondition of the other) would for instance be a reactive shunt device needed to avoid voltage upper limit violations due to the addition of the new investment.
- An example of projects that should be clustered could be the following: a border-link without a second project has a GTC increase which is 200MW; also suppose that the second project on its own delivers a GTC increase of 150MW. But both projects together deliver a GTC increase of 500MW, In this case these two lines should be treated as a cluster, and treated as investment 1 in the above. If there are additional lines, which could be part of the cluster as well, the "normal" method, has to be used with the starting GTC of (in this example) 500 MW.
- Further, if in the above example the border-link delivers a GTC increase of 300MW, and combined with the second project delivers an overall GTC increase of 500MW, then the two projects can be clustered together[12].

3.3. Assessment framework

The assessment framework is a combined cost-benefit and multi-criteria assessment[13], complying with Article 12 and Annexes IV and V of the Regulation Guidelines on Trans-European energy infrastructures. The criteria set out in this document have thus been selected on the following basis:

- They enable an appreciation of project benefits in terms of EU network objectives:
    - ensure the development of a single European grid to permit the EU climate policy objectives (RES, energy efficiency, CO_2);

[12] However, there may also be reasons to treat the border-link on its own as one project of GTC increase 300MW, and the second line as a follow-on project of +200MW.

[13] More details on multi-criteria assessment versus cost-benefit analysis are provided in Annex 2.

- guarantee security of supply;
- complete the internal energy market, especially through a contribution to increased socio-economic welfare ;
- ensure technical resilience of the system,

- They provide a measurement of project costs and feasibility (especially environmental and social viability).
- The indicators used are as simple and robust as possible. This leads to simplified methodologies for some indicators.
  The principles underlying this document also include the results of the consultation on the 2010 and 2012 TYNDP, as well as a specific Stakeholder Workshop on the assessment of PCIs.

Figure 9 shows the main categories that group the indicators used to assess the impact of projects.

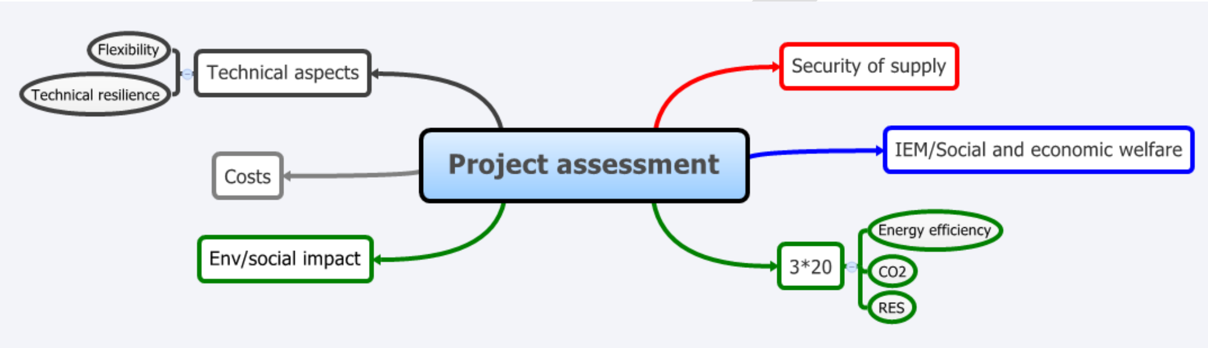


Figure 9. Main categories of the project assessment methodology

Some projects will provide all the benefit categories, whereas other projects will only contribute significantly to one or two of them. Other benefits, such as benefits for competition[14], also exist. These are more difficult to model, and will not be explicitly taken into account.

This assessment must be done independently for each evaluated scenario.

The **Benefit Categories** are defined as follows:

B1. Improved security of supply[15] (SoS) is the ability of a power system to provide an adequate and secure supply of electricity under ordinary conditions[16].

B2. Socio-economic welfare (SEW)[17] is characterized by the ability of a power system to reduce congestion and thus provide an adequate GTC so that electricity markets can trade power in an economically efficient manner[18].

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[14] Some definitions of a market benefit include an aspect of facilitating competition in the generation of electricity. These Guidelines are unable to well-define any metric solely relating to facilitation of competition. If transmission reinforcement has minimised congestion, that has facilitated competition in generation to the greatest extent possible. For further developments, see Annex 1.

[15] Adequacy measures the ability of a power system to supply demand in full, at the current state of network availability; the power system can be said to be in an N-0 state. Security measures the ability of a power system to meet demand in full, and to continue to do so under all credible contingencies of single transmission faults; such a system is said to be N-1 secure.

[16] This category covers criteria 2b of Annex IV of the Regulation, namely “secure system operation and interoperability”.

[17] 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).

[18] This category contributes to the criteria ‘market integration” set out in Article 4, 2a and to criteria 6b of Annex V, namely “evolution of future generation costs”.

B3. RES integration. Support to RES integration is defined as the ability of the system to allow the connection of new RES plants and unlock existing and future "green" generation, while minimizing curtailments[19].

B4. Variation in losses in the transmission grid is the characterization of the evolution of thermal losses in the power system. It is an indicator of energy efficiency[20] and is correlated with SEW.

B5. Variation in CO_2 emissions is the characterization of the evolution of CO_2 emissions in the power system. It is a consequence of B3 (unlock of generation with lower carbon content)[21].

B6. Technical resilience/system safety is the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies)[22].

B7. Flexibility is the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios, including trade of balancing services[23].

The **project costs** are defined as follows:

C1. Total project expenditures are based on prices used within each TSO and rough estimates on project consistency (e.g. km of lines …). Land costs, costs of obtaining permissions, and damages vary between TSOs. The project cost should consider life cycle costs.

The **Project impact on society** is defined as follows:

S.1. Social and Environmental sensibility characterizes the project impact as perceived by the local population and assessed through preliminary studies, and as such gives a measure of the social and environmental sensibility associated with the project.

The Grid Transfer Capability is defined as follows:

The GTC reflects the ability of the grid to transport electricity across a boundary, i.e. from one bidding area (area within a country or a TSO) to another, or at any other relevant cross-section of the same transmission corridor having the effect of increasing this cross-border GTC. However, GTC variation may also be within a country, increasing security of supply or generation accommodation capacity over an internal boundary. In this way, three different categories of Grid Transfer Capability have been considered:

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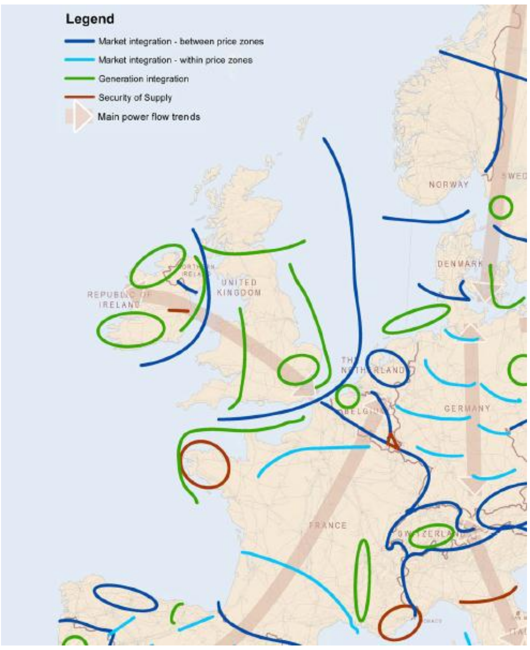
[19] This category corresponds to the criterion 2a of Article 4, namely "sustainability", and covers criteria 2b of Annex IV.

[20] This category contributes to the criterion 6b of Annex V, namely "transmission losses over the technical lifecycle of the project".

[21] This category contributes to the criterion « sustainability » set out in Article 4, 2b and to criteria 6b of Annex V, namely costs "related to greenhouse gas emissions"

[22] This category contributes to the criterion "interoperability and secure system operation" set out in Article 4, 2b and to criteria 2d of Annex IV, as well as to criteria 6b of Annex V, namely "system resilience".

[23] This category contributes to the criterion "interoperability and secure system operation" set out in Article 4, 2b , and to and to criteria 2d of Annex IV, as well as to criteria 6e of Annex V, namely "operational flexibility".



Generation accommodation capability is the capability used for the accommodation of both new and existing generation. It allows the increase of generation in the exporting area and the decrease of generation in the importing area. The variations of generation follow the merit order established by the market until the marginal costs of border areas converge or the safety rules as explained in chapter 4 are no longer respected.

Security of supply capability is the capacity that is necessary for avoiding load shedding in a specific area when ordinary contingencies are simulated.

Exchange capability between bidding areas is the maximum GTC that can be designated to commercial exchanges.

Figure 10: Illustration of GTC boundaries (source: TYNDP 2012)

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 described in chapter 4. The Grid Transfer Capability is oriented, which means that across a boundary there may be two different values. A boundary may be fixed (e.g. a border between states or bidding areas), or vary from one horizon or scenario to another. Grid projects provide an increase of GTC that can be expressed in MW.

The GTC value that is displayed must be valid at least 30 % of the time. The variation of GTC over the year may be given as a range in MW (max, min).
A project with a GTC increase of at least 500 MW compared to the situation without commissioning of the project is deemed to have a significant cross-border impact.

Assessment summary table

The collated assessment findings are shown diagrammatically in the form of an assessment table, including the seven categories of benefits mentioned above, as well as two "impact" indicators (costs and socio-environmental sensibility). In addition, a "neutral" characterization of the project is provided through an assessment of the GTC increase.

Light green is systematically used for mild effects, green for benefits with medium effects and dark green for those having a strong impact. Thresholds for each category are given in euros when this is deemed possible, and in physical units or KPIs in the other cases. Indeed, some effects of the project, whilst relevant, cannot be monetized in a homogenous and reliable way throughout Europe. For transmission projects, some externalities (such as security of supply) are essential in decision-making, and it is important to place them appropriately. In the assessment table this is done through a color code that will convey the required message to those studying it. The color code is completed by a quantitative assessment when available.

At least scenarios will be used for cost benefit analysis (see chapter 2.2). Generally, the results of the reference scenario will be displayed in the table. The results of other scenarios and sensitivity analysis may populate the assessment summary table as intervals.

Grid transfer capabilité increase	Social and economic welfare (€)	Security of supply (MWh)	RES integration (MWh)	CO2 emissions variation (kt)	Losses variation (€)	Technical resilience (++/--)	Flexibility (++/--)	Costs (€)	Environmental sensibility (++/--)
MW	*Minor benefit*			*Neutral/ no clear trend*	*Negative benefit*			*High cost*	*High risk*
	Medium benefit							*Medium cost*	*Medium risk*
	High benefit							*Low cost*	*Minor risk*

Figure 11. Example of assessment summary table

3.4. Grid Transfer Capability calculation

The identification of exchange limits (GTC) among bidding areas is obtained starting from stressed network situations that are suitable for highlighting the contributions of the reinforcement. A common grid model is used to assess the future grid transfer capability and behavior with the planned projects, and the resilience in stressed grid situations, taking into account the security criteria described in chapter 4. The delta GTC value (allowed by the reinforcement) takes into account congestions on the grid (observed in grid studies), both inside and between bidding areas. It represents the GTC variation obtained by the whole project (including the clustered internal reinforcement if needed; see 3.2).

3.5. Cost and environmental liability assessment

C.1. Total project expenditure[24]

For each project, costs have to be estimated. The following items should be taken into account:

- Expected cost for materials and assembly costs (such as masts/ basement/ wires/ cables/ substations/ protection and control systems);
- Expected costs for temporary solutions which are necessary to realize 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);
- Expected costs for approval procedure (such as planning approval, regional planning procedure, compensation costs and so on);
- Expected costs for devices that have to be replaced within the given period (regard of life-cycles) ;
- Dismantling costs at the end of life of the equipment.
- Other life cycle costs.

For transmission projects, time horizon is generally shorter than the technical life of the assets. Transmission assets have a technical lifetime up to 80 years, but uncertainty regarding the evolution of generation and consumption at such horizons is so large that no meaningful cost-benefit analysis can be performed. An appropriate <u>residual value</u> will therefore be included in the end year, using the standard economic depreciation formula used by each TSO or project promoter.

[24] Calculation shall comply with Annex V, §5.

Indicative colors are assigned as follows:

Light green: total expenditures higher than 1000 M€

Green: total expenditures between 300 M€ and 1000 M€

Dark green: total expenditures lower than 300 M€

S.1. Social and environmental sensibility

Social and environmental sensibility characterizes the project impact as perceived by the local population and assessed through preliminary studies, and as such, gives a measure of the social and environmental sensibility associated with the project. The impact on nature (e.g. biodiversity), human activity and social compatibility (e.g. visual impact) is analyzed. Early assessment of social and environmental sensibility will help to increase social compatibility and successful licensing. The indication is established through an expert assessment, supported by preliminary environmental studies.

Indicative colors are assigned as follows:

Light green: desk-top studies indicate that sensibility is low (no protected or dense urban area is affected, there are no known former infrastructure conflicts in the area, the visual impact is perceived as low).

Amber: desk-top studies indicate that sensibility is medium (protected or urban area may be affected in a limited way, visual impact is perceived as moderate).

Red: desk-top studies indicate that sensibility is high (visual impact is perceived as high, protected or urban area may be affected, there have been former conflicts in the area).

3.6. Boundary conditions and main parameters of benefit assessment

3.6.1 Geographical scope

The rationale behind system modeling is to use very detailed information within the studied area, and a decreasing level of detail when deviating from the studied area. The geographical scope of the analysis is an ENTSO-E Region at minimum, including its closest neighbors. 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[25]. Finally, in order to take into account the interaction of the pan-European modeled system, exchange conditions will be fixed using hourly steps, based on a global market simulation[26].

3.6.2 Time frame

The results of cost benefit analysis depend on the chosen period of study. The period of analysis starts with the commissioning date and extends to a time frame covering the study horizons. It is generally recommended to study two horizons, one midterm and one long term (see chapter 2). To evaluate projects on a common basis, benefits should be aggregated across years as follows:

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25 Annex V, §10 of the Regulation.

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

- For years from year of commission (start of benefits) to midterm (if any), extend midterm benefits backwards.
- For years between midterm and long term, linearly interpolate benefits between the midterm and long term values.
- For years beyond long term horizon (if any), maintain benefits at long term value.

3.6.3 Discount rate

The purpose of using a discount rate is to convert future monetary benefits and costs into their present value, so that they can be meaningfully used for comparison and evaluation purposes. The discount rate reflects the time value of money as well as the risk linked to future costs and benefits.
The discount rate can be calculated as a real or a nominal rate. However, this choice must be consistent with the valuation of costs and benefits: real prices implies real rates, nominal prices imply nominal rate. Real prices must take into account specific deviation from inflation for costs and benefits.
Both costs and benefits have to be discounted to the commissioning year.

To fix the social discount rate, one has to consider:

- A lower bound (the return of the planned investment should yield at least an opportunity cost higher than):
  - The risk free rate (which can be a mean of governmental bond of countries financing the project, or the cost of debt of project promoters if available), and/or
  - Gross Domestic Product (GDP) growth rate[27] (which can be a mean of expected future growth rates in the countries financing the project).
- A higher bound: the return of the planned investment should yield an opportunity cost below the highest cost of debt observed in the countries financing the project.

Moreover, for comparison purposes and simplicity, following the EC guide on CBA (page 208-210), each Regional Group should choose a unique discount rate for the projects in the region, except when the project covers both countries that are beneficiary of the Cohesion Fund[28] and countries that are not. As a minimum, a single discount rate must be used for each project. The discount rate for interconnectors may therefore be different from the regulatory rate of return of transmission assets for each TSO.
No discount rate will be applied for non-monetary benefits: these cases will use values obtained for the reference long term horizon. Values for the midterm horizon will be used for robustness analysis.

3.6.4 Benefit analysis

Two possible ways for project evaluation can be adopted:

- the **Take Out One at the Time (TOOT)** methodology, that consists of excluding investment items (line, substation, PST or other transmission network device) or complete projects from the forecasted network structure on a one-by-one basis and to evaluate the load flows over the lines with and without the examined network reinforcement (a new line, a new substation, a new PST, ..);
- the **Put IN one at the Time (PINT)** methodology, that considers each new network investment/project (line, substation, PST or other transmission network device) on the given

[27] As set in the top-down Reference scenarios.

[28] The Cohesion Fund contributes to interventions in the field of the environment and trans-European transport networks. It applies to member states with a Gross National Income (GNI) of less than 90% of the EU average.

network structure one-by-one and evaluates the load flows over the lines with and without the examined network reinforcement.

The TOOT method provides an estimation of benefits for each project, as if it was the last to be commissioned. In fact, the TOOT method evaluates each new development investment/project into the whole forecasted network. The advantage of this analysis is that it immediately appreciates every benefit brought by each investment item, without considering the order of investments. All benefits are considered in a precautionary way, in fact each evaluated project is considered into an "already developed" environment, in which are present all programmed development projects and are reported conditions in which the new investment shall operate. Hence, this method allows analyses and evaluations at TYNDP level, considering the whole TYNDP vision and every network evolution.

The TOOT methodology is recommended for cost-benefit analysis of a transmission plan such as the TYNDP, whereas the PINT methodology is recommended for individual project assessments outside the TYNDP process. The TYNDP network is then considered as the reference grid.

3.7. Methodology for each benefit indicator

B1. Security of supply

Introduction

Security of Supply is the ability of a power system to provide an adequate and secure supply of electricity in ordinary conditions, in a specific area. The assessment must be performed for a geographically delineated area with an annual electricity demand of at least 3 TWh[29]. The boundary of the area may consist of the nodes of a quasi-radial sub-system or semi-isolated area (e.g. with a single 400 kV injection). Two examples are provided below (project indicated in orange[30]).

[29] This value is seen as a relevant threshold for electricity consumption for smart grids in the draft Regulation

[30] One should take notice that although the definition of a 'delimited geographical area' that is made subject to Security of Supply calculation may be considered an arbitrary exercise, the indicator score (see below) is determined proportionally to the size of the area (i.e. its annual electricity demand). In order to be scored the same, a larger geographic area thus requires a larger absolute improvement in Security of Supply compared to a smaller area.

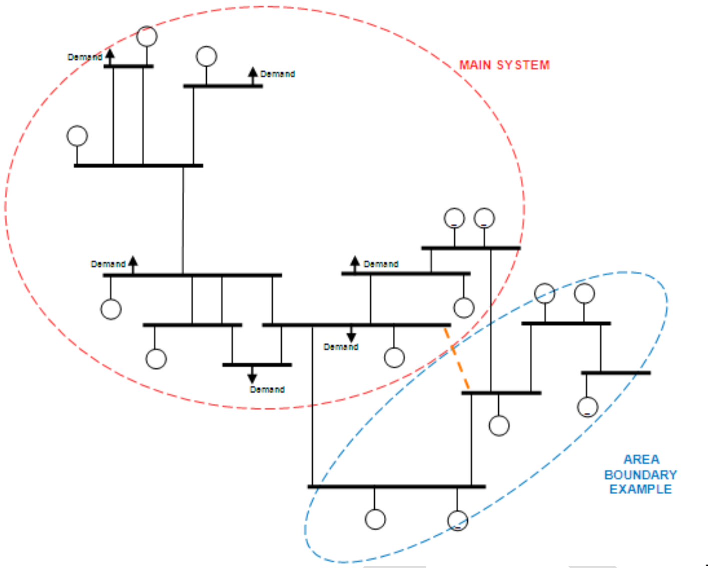


Figure 12:Iillustration of delimited area for security of supply calculations

The criterion measures the improvement to security of supply (generation or network adequacy) brought about by a transmission project. It is calculated as the difference between the cases with and without the project, with the defined indicator being either Expected Energy Not Supplied (EENS) or the Loss of Load Expectancy (LOLE).

Methodology

Depending on the issue at stake, market or network models are used for the assessment calculations. When dealing with generation adequacy issues, market models are used to determine the contribution of a project to deliver power that was generated somewhere in the system to this specific area. Network models, on the other hand, are preferred for network adequacy issues, i.e. to determine the contribution of a project to network robustness (risk of network failures leading to lost load). The benefit evaluation methodology from Section 3.6.4 is used in both cases.

For network studies, performance assessment is based on the technical criteria defined in Chapter 4. Analysis of representative cases without the project may, for example, identify risk of loss of load for ordinary contingencies. The EENS indicator will then show whether the inclusion of the project triggers a significant improvement of security of supply (see scale below).

The market based analysis relies on the same system tests, but with a simplified network representation. This assessment examines the likelihood of risks to the security of supply across an entire year in a wide range of stochastic scenarios regarding load and generation, and therefore may determine the probability of a critical system state. As such, this analysis will yield an Expected Energy Not Supplied (EENS) measure in MWh/year or a Loss of Load Expectancy (LOLE) in hours/year. Similar to the network based analysis, the inclusion of the project will identify the contribution that the project makes to either the EENS or LOLE indicators.

Both kinds of indicators may be used for the project assessment, depending on the issues at stake in the area. However, the method that is used must be reported (see table below).

Monetization

In theory, the unreliability cost could be obtained using the EENS index and the unit interruption cost (i.e. Value Of Lost Load ; VOLL). In reality, however, the monetization of system unreliability and security of supply using VOLL cannot be performed uniformly on a Union-wide basis. There is a large variation in the value that different customers place on their supply[31] and this variation can differ greatly across the Union, as it depends largely on regional and sectorial composition and the role of the electricity in the economy[32]. Additional factors such as time, duration and number of interruptions over a period also influence VOLL. The CEER has set out European guidelines[33] in the domain of 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*[34]*"*.

Given the high variability and complexity of the VOLL, calculating project benefit using market based assessment will only provide indicative results which cannot be monetized on a Union-wide basis. VOLL will therefore not be used as a basis for comparative EENS or LOLE calculations.

Parameter	Source of calculation[35]	Basic unit of measure	Monetary measure (externality or market based?)	Level of coherence
Loss Of Load Expectancy (LOLE)	Market studies (Generation adequacy)	Hours or MWh	Value of Lost Load	National
Expected Energy Not Supplied (ENS)	Network studies (network adequacy/ secure system operation)	MWh	Value of Lost Load	National

Indicative colors are assigned as follows:

Light green: the project has no measurable impact on security of supply;

Green: the project increases the security of supply for an area of annual energy demand greater than 3 TWh by more than 0.001% of annual consumption[36];

Dark green: the project increases the security of supply for an area of annual energy demand greater than 3 TWh by more than 0.01% of annual consumption[37].

[31] The University of Bath, in the framework of the European project CASES ("WP5 Report (1) on National and EU level estimates of energy supply externalities") states that "it is safe to conclude that VOLL figures [in 2030] lay in a range of 4-40 $/kWh for developed countries" (estimation based on a literature review).

[32] Cf CIGRE study, 2001.

[33] Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, CEER, December 2010

[34] However, this has not been done everywhere. Hence, there is no full set of available and comparable national VOLLs across Europe.

[35] Cf Annex IV, 2c.

[36] For an area with an annual consumption of 3 TWh this would equal 30 MWh/yr (6 minutes of average demand).

[37] For an area with an annual consumption of 3 TWh this would equal 300 MWh/yr (60 minutes of average demand).

B2. Socio-economic welfare

Introduction

A project that increases GTC between two bidding areas allows generators in the lower-priced area to export power to the higher-priced (import) area, as shown below. The new transmission capacity reduces the total cost of electricity supply. Therefore, a transmission project can increase socio-economic welfare.

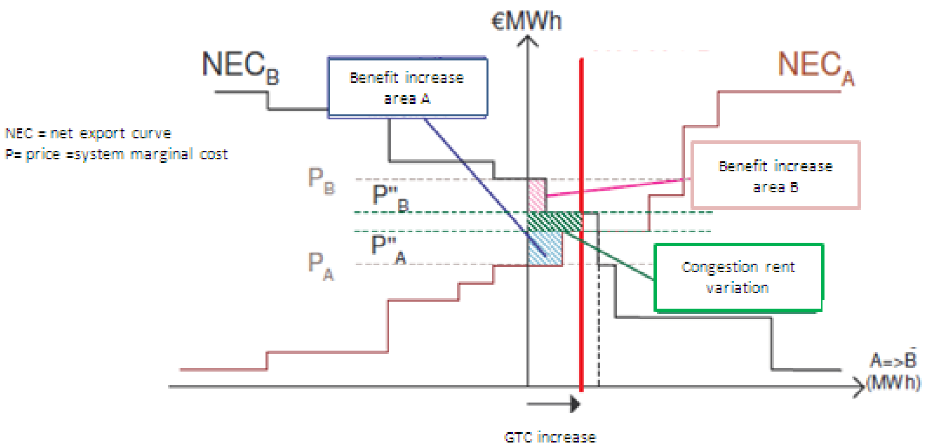


Figure 13:Iillustration of benefits due to GTC increase between two bidding areas

In this chapter we consider a perfect market 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 for calculating the increased benefit from socio-economic welfare:

- The generation cost approach, which compares the generation costs with and without the project for the different bidding areas.
- 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[38].

The choice of method for the cost-benefit analyses has to be decided within ENTSO-E's regional groups.

A key item for this choice is the evaluation of the demand flexibility or price elasticity. Most of the European countries are presently considered to have price inelastic demand. However, there are various developments that appear to cause a more elastic demand-side. Both the development of smart grids and smart metering, as well as a growing flexibility needs 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 ENSTO-E’s regional groups:

1) The demand that will have to be supplied by generation is estimated through various

[38] More details about how to calculate surplus are provided in Annex 3

scenarios, reshaping the demand curve (in comparison with present curves) to model the future introduction of smart grids, electric vehicles...etc. The demand response will not be exactly demand elasticity at each hour, but a movement of energy consumption from hours of (potential) high prices to hours of (potential) low prices. The generation costs to supply a known demand are minimized through the generation cost approach. This assumption simplifies the complexity of the models, in that 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. Again, two methods are possible:
    a. Using the generation cost approach, price elasticity could be taken into account via the modeling of curtailment as generators. The "willingness to pay" would then 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 modeling 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.

Project appraisal is based on analyses of the global (European) increase of welfare. This means that the goal is to bring up the projects which are the best for the European power system. For all the analyses third-party projects are to be assessed in the same way as projects between TSOs.

<u>Generation cost approach</u>

A perfect market is assumed, where producers offer electricity at the level of short term marginal cost of generation. Hence, for a given power plant, marginal costs cover start-up costs (depending on the start-up conditions), as well as variable costs (depending on actual generation: fuel, standard efficiency rate, standard CO_2 emission rate and variable costs for operation and maintenance). In this model, price equals the marginal cost of generation. Advanced models can also include assumptions on capital cost recovery.

The socio-economic welfare benefit is calculated from the reduction in total generation costs associated with the GTC 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 directly expressed by Benefit Category B3 'RES Integration'. In other cases, the direct connection figures will be available in the background scenarios.

c. A project can also facilitate increased competition between generators, reducing the price of electricity to final consumers. Our methods do not consider market power (see annex 1), and as a result our expression of socio-economic welfare is the reduction in generation costs under (a).

An economic optimization is undertaken to determine the optimal dispatch cost of generation, with and without the project. The benefit for each case is calculated from:

Benefit (for each hour) = Generation costs without the project – Generation costs with the project

The socio-economic welfare can be calculated for internal constraints by considering virtual smaller bidding areas (with different market prices) separated by the congested internal boundary inside an official bidding area.

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.

Total surplus approach

In case of price-elastic demand or if the welfare increase is estimated per member state/bidding area, welfare must be calculated by a total surplus approach. In general this method is more complicated than the generation cost approach in terms of both models and analyses. The socio-economic welfare benefit is calculated by adding the producer surplus, the consumer surplus and the congestion rents for all price areas. The total surplus approach consists of the following three items:

a. By reducing network bottlenecks, the total generation cost will be economically optimized. This is reflected in the sum of the producer surpluses.
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.
c. Finally, reducing network bottlenecks will lead to a change in total congestion rent for the TSOs.

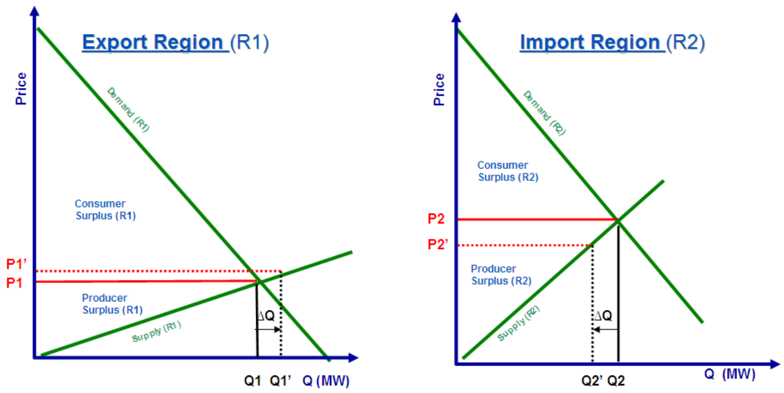


Figure 14: Example of a new project increasing GTC between an export and an import region.

An economic optimization is undertaken to determine the total sum of the producer surplus, the consumer surplus and the change of congestion rent, with and without the project. The benefit for each case is calculated by:

Benefit (for each hour) = Total surplus with the project – Total surplus without the project

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.

Parameter	Source of calculation[39]	Basic unit of measure	Monetary measure (externality or market based?)	Level of coherence of monetary measure
Reduced generation costs/ additional overall welfare	Market studies (optimization of generation portfolios across boundaries)	€	idem	European
Internal dispatch costs	Network studies (optimization of generation dispatch within a boundary considering grid constraints)	€	idem	National

Indicative colors are assigned as follows:

Light green : the project has an annual benefit < € 30 million

Green: the project has an annual benefit between € 30 and € 100 million

Dark green: the project has an annual benefit > or = to € 100 million

B3. RES integration[40]

Introduction

The integration of both existing and planned RES is facilitated by:

1. Connection of RES generation to the main system,
2. Increasing the GTC between an area with excess RES generation to other areas, in order to facilitate higher level of RES penetration.

This indicator intends to provide 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 GTC in the main system itself.

Methodology

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 GTC-based indicator (2) is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system. Avoided spillage is extracted from the studies for indicator B2. Connected RES is derived from network studies. Both kinds of indicators may be used for the project assessment, provided that the method used is reported (see table below).

Monetization

Any monetization of this indicator will be reported by B2. The benefits of RES in terms of CO2 reduction will be reported by B5.

Parameter	Source of calculation[41]	Basic unit of measure	Monetary measure (externality or market based?)	Level of coherence of monetary measure
Connected RES	Market or network studies	MW	None	European
Avoided RES spillage	Market or network studies	MWh	Included in generation cost savings (B2)	European

Indicative colors are assigned as follows:

White: the project has a neutral effect on the capability of integrating RES, i.e. allows less than 100 MW of direct RES connection or increases RES generation by less than 50 GWh

Light green: the project allows direct connection of RES production between 100 and 500 MW or permits an increase in RES generation between 50 GWh and 300 GWh

Dark green: the project allows direct connection of RES production greater than 500 MW or increases RES generation by more than 300 GWh

40 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.

41 Cf. Annex IV, 2c.

B4. Variation in losses (Energy efficiency)

Introduction

The energy efficiency benefit of a project is measured through the reduction of thermal losses in the system. At constant transit levels, network development generally decreases losses, thus increases 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 higher need for transit over long distances, which increases losses.

Methodology

Variation in losses can be calculated by a combination of market and network simulation tools. The losses in the system are quantified for each planning case (covering seasonal variations) on the basis of network simulation. This is done both with and without the project, while taking into account the change of dispatch that may occur by means of market simulation. The variation in losses is then calculated as the difference between both values, which can be monetized (see below).

Monetization

Monetization of losses is based on forecasted marginal costs in the studied horizon. These marginal costs are derived from market studies, which must ensure that input parameters are coherent with the parameters and assumptions indicated in chapter 2.

Parameter	Source of calculation[42]	Basic unit of measure	Monetary measure (externality or market based?)	Level of coherence of monetary measure
Losses	Network studies	MWh	€/year (market based)	European

Indicative colors are assigned as follows:

- Red: the project increases the volume of losses on the grid
- White: the project decreases losses in some situations and increases them in others
- Light green: the project decreases the volume of losses on the grid.

[42] Cf Annex IV, 2c.

B5. Variation in CO_2 emissions

Introduction

By relieving congestion, reinforcements may enable low-carbon generation to generate more electricity, thus replacing conventional plants with higher carbon emissions. Considering the specific emissions of CO2 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 (see chapter 2).

Methodology

Generation dispatch and unit commitment used for calculation of socio-economic welfare benefit with and without the project is used to calculate the CO2 impact, taking into account standard emission rates.

Monetization

The monetization of CO2 is based on forecasted CO2 prices for electricity in the studied horizon. The price is derived from official sources such as the IEA for the studied perimeter (see chapter 2). As the cost of CO2 is already included (internalized) in generation costs (B2), the indicator only displays the benefit in tons in order to avoid double accounting.

However, it is possible that the prices of CO2 included in the generation costs (B2) under-state the full long-term societal value of CO2. Accordingly, a sensitivity analysis (see chapter 3.8) could be performed for this indicator B5, under which CO2 is valued at a long-term societal price. To perform this sensitivity without double-counting against B2:

a. Derive the delta volume of CO2, as above.

b. Consider the CO2 price internalized in B2.

c. Adopt a long-term societal price of CO2.

d. Multiply the volume of (a) by the difference in prices (c) minus (b). This represents the monetization of this sensitivity of an increased value of CO2[43].

Parameter	Source of calculation	Basic unit of measure	Monetary measure	Level of coherence
CO2	Market and network studies (substitution effect)	tons	CO2 price derived from generation costs (internalized in B2)	European

Indicative colors are assigned as follows:

White: the project has no positive effect on CO2 emissions

Green: the project reduces CO2 emissions by < 500 kt/year [44]

Dark green: the project reduces CO2 emissions by > 500 kt/year

[43] Note: for this sensitivity to B5, one does not adjust the merit order and the dispatch for B2 for the higher Carbon price. If one were to perform that exercise, that would represent a full re-run of indicator B2, against the different data assumption of a higher forecast carbon price included in the generation background and merit order.

[44] The 500 kt limit is considered as a significant threshold for CO2 monitoring in the Commission Decision of 18 July 2007 on monitoring and reporting guidelines pursuant to Directive 2003/87/EC

B6. Technical resilience/system safety margin

Making provision for resilience while planning transmission systems contributes to system security during contingencies and extreme scenarios. This improves a project's ability to deal with the uncertainties in relation to the final development and operation of future transmission systems. Factoring resilience into projects will impact positively on future efficiencies and on ensuring security of supply in the European Union.

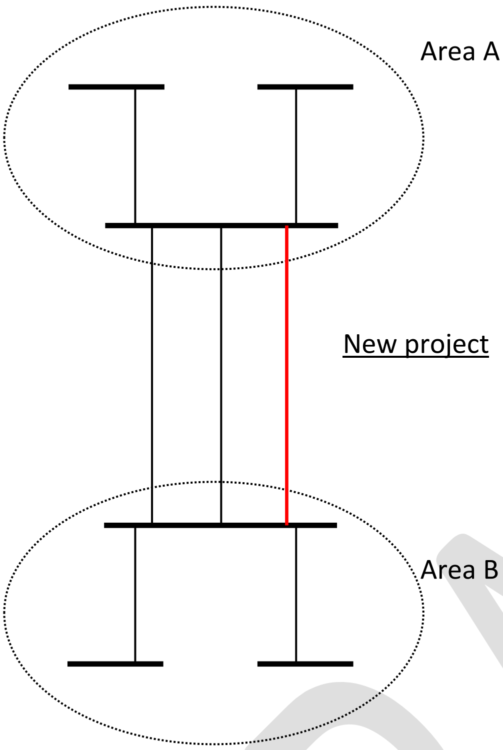
A quantitative summation of the technical resilience and system safety margins of a project is performed by scoring a number of key performance indicators (KPI) and aggregating these to provide the total score of the project.

KPI	Score (either ++/+/0)
Able to meet the recommendation R.1 (failures combined with maintenance) set out in chapter 4 (as applicable)	
Able to meet the recommendation R.2 (steady state criteria) set out in chapter 4 (as applicable)	
Able to meet the recommendation R.3 (voltage collapse criteria) set out in chapter 4 (as applicable)	

A Union-wide list of projects of common interest will be of a wide type and range. Given this high degree of variability and the complexity of assessing the contribution of a project to resilience, the technical resilience benefit will be based on professional power engineering judgment rather than only an algorithmic calculation. More specifically, the KPI score is based on an engineer's detailed knowledge of the development and specifics of the relevant network in the context of the project under assessment. The KPI may therefore be supported by additional studies which demonstrate this benefit. The general rule is as follows:

The assessment of each KPI will be undertaken in TOOT for planning cases that are representative of the relevant year (see chapter 2). If a particular project contributes positively in the assessment of at least one KPI then it should score at least a single '+'. If a project contributes positively in the assessment of a particular KPI then it should score at least a single '+'. If the project does not completely meet the recommendations of a particular KPI then it cannot score a '++'.

Methodology



Based on the analyzed new project's ability to comply with failures combined with maintenance (n-1 during maintenance) (R.1), the analyzed project should be evaluated with a score that varies between a score of 0, a single or double '+'. (0/+/++).

Based on the analyzed new project's ability to comply with steady state criteria in case of exceptional contingencies (R.2), the analyzed project should be evaluated with a KPI that varies between a score of 0, a single or double '+'. (0/+/++).

Based on the analyzed new project's ability to cope with voltage collapse criteria (R.3), the analyzed project should be evaluated with a KPI that varies between a score of 0, a single or double '+'. (0/+/++).

Scores for all KPIs are added.

Indicative colors are assigned as follows:

White: the score of KPIs is 0

Green: the score of KPIs is < or = 3+

Dark green: the score of KPIs is > 3 +

B7. Robustness/flexibility

The robustness of a transmission project is defined as the ability to ensure that the needs of the system are met in a future scenario that differs from present projections (sensitivity scenarios concerning input data set[45]). The provision and accommodation of operational flexibility, which is needed for the day-to-day running of the transmission system, must also be acknowledged. The robustness and flexibility of a project will ensure that future assets can be fully utilized in the longer term because the uncertainties related to development and transmission needs on a Union-wide basis are dealt with adequately. Moreover, special emphasis is given to the ability to facilitate the sharing of balancing services, as we suppose that there will be a growing need for this in the coming years.

A qualitative summation of the robustness and flexibility of a project is performed using TOOT by scoring a number of key performance indicators and aggregating these to obtain the total impact of the project.

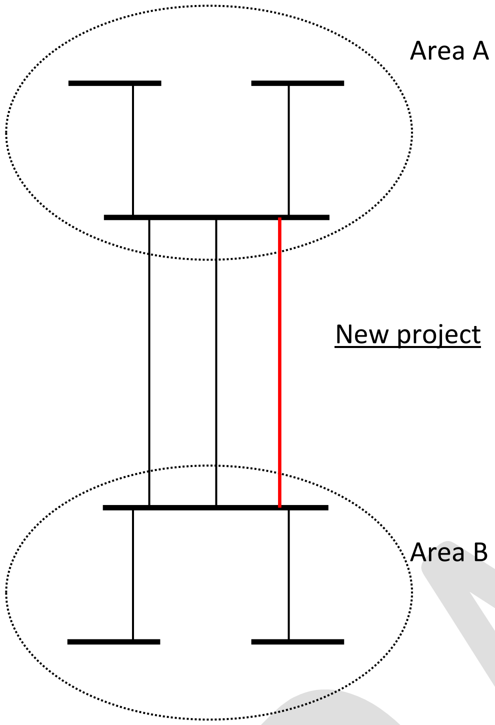
KPI	Score (either ++/+/0)
Ability to comply with all cases analyzed using a probabilistic or multi-case approach as set out in chapter 2 (as applicable)	
Ability to comply with all cases analyzed taking out some of the foreseen reinforcements as set out in chapter 2 (as applicable)	
Ability to facilitate sharing of balancing services on wider geographical areas, including between synchronous areas	

Given the highly variable and complex nature of each project, and the prohibitive number of possible future developments on a Union-wide scale, it is infeasible to accurately calculate or monetize the performance of each project with respect to flexibility. The benefits are therefore defined by a tabulated scoring system (outlined above) which is completed by professional power engineering judgment rather than by algorithmic calculation.

Scores for each KPI are added to the table and are summated to give an overall score for the project. Each KPI can be given a score of 0, ‘+’, or '++'. The methodology for the scoring of each KPI is outlined below.

[45] See chapter 2 for definition of a sensitivity scenario.

Methodology



Based on the analyzed new project's ability to comply with important sensitivities, the analyzed project should be evaluated with a KPI that varies between a score of 0, a single or double ‘+’. (0/+/++).

Based on the analyzed new project's ability to comply with commissioning delays and local objection to the construction of the infrastructure, the analyzed project should be evaluated with a KPI that varies between a score of 0, a single or double ‘+’. (0/+/++).

Based on the analyzed new project's ability to share balancing services in a wider geographical area (including between synchronous areas), the analyzed project should be evaluated with a KPI that varies between a score of 0, a single or double ‘+’. (0/+/++).

Scores for all KPIs are added.

Indicative colors are assigned as follows:

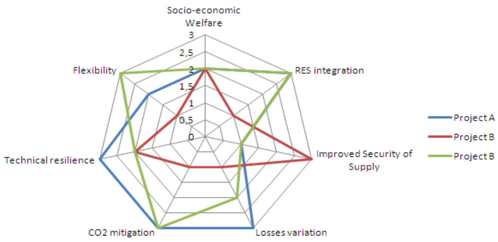
- White: the score of KPIs is 0
- Green: the score of KPIs is < or = 3+
- Dark green: the score of KPIs is > 3+

3.8. Overall assessment and sensitivity analysis [46]

3.8.1 Overall assessment

The overall assessment is displayed as a multi-criteria matrix, as shown in chapter 3.3. All indicators are quantified. Costs, socio-economic welfare and variation of losses are displayed in euros. The other indicators are displayed through the most relevant units ensuring both a coherent measure all over Europe and an opposable value, while avoiding double accounting in euros. Indeed, some benefits like CO2 and RES are already internalized in socio-economic welfare.

Furthermore, each indicator is qualified on a multiple level color scale, expressing negative, neutral, minor positive, medium positive or high positive impact. This scale allows displaying the results in various formats, such as the "classical" color code or radar formats as shown below.



Criteria	Project assessment									
	Grid Transfer Capability Increase	Socio-economic Welfare	RES integration	Improved Security of Supply	Losses variation	CO2 mitigation	Technical resilience	Flexibility	Social and environmental Impact	Project costs
	MW	M€/year	MWh/year	MWh/year	M€	Mt				M€
Project A	1000	150	500			0,5	+++	++		650
Project B	500	30		3000	20		++			25
Project C	800	225	3000		10	1	++	+++		150

Figure 15: illustration of overall assessment

3.8.2 Sensitivity analysis

Transmission network planners face an increasing number of uncertainties. At the macroeconomic level, future evolution of the volume and the type of generation, trends in demand growth, energy prices and exchange patterns between bidding areas are uncertain, and greatly influence the need for transmission capacity. At the level of the study area, generation location and availability, as well as network evolution and availability, also have a major impact on network structure and location. The cost benefit methodology addresses these uncertainties in several ways:

- Benefit indicators are generally expected values, i.e. values obtained through a range of planning cases[47].
- Projects are assessed in at least two carefully considered macro-economic scenarios;
- The robustness of each project against variation of different scenarios or cases is assessed through indicator B7.

Additional sensitivity analysis (varying selected key assumptions whilst fixing all of the other assumptions) may be carried out, and the following parameters could for instance be considered for sensitivity analysis:

- Demand forecast;
- Fuel costs and RES value;
- CO2 price;
- Discount rate;
- Commissioning date.

[46] As stated in 1.2, this guideline sets out the approach to measure each of the seven benefit indicators for each project. In order to ensure a full assessment of all transmission benefits, some are monetized, while others are measured through physical units such as tons or kWh. This set of common European-wide indicators will form a complete and solid basis, both for project evaluation within the TYNDP, and project portfolio development for the PCI selection process.

[47] With probabilistic market tools, the expected values may even be the results of hundreds of scenarios.

4. TECHNICAL CRITERIA FOR PLANNING

Technical methods and criteria are defined to be used when assessing the planning scenarios, in order to identify future problems and determine the required development of the transmission grid.

The general methodology implies:

Grid analysis.

- Investigation of base case topology (all network elements available).
- Different types of events (failures of network elements, loss of generation, …) are considered depending on their probability of occurrence.

Evaluation of results.

- Evaluation of consequences by checking the main technical indicators:
  - Cascade tripping.
  - Thermal limits.
  - Voltages.
  - Loss of demand
  - Loss of generation
  - Short circuit levels
  - Stability conditions.
  - Angular difference.
- Acceptable consequences can depend on the probability of occurrence of the event.

Currently deterministic criteria are used in the planning of the grid.

4.1. Definitions[48]

D.1. **Base Case for network analysis.** Data used for analysis are mainly determined by the planning cases. For any relevant point in time, the expected state of the whole system, "with all network equipment available", forms the basis for the analysis ("Base case analysis").

D.2. **Contingencies**. A contingency is the loss of one or several elements of the power transmission system. A differentiation is made between ordinary, exceptional and out-of-range contingencies. The wide range of climatic conditions and the size and strength of different networks within ENTSO-E mean that the frequency and consequences of contingencies vary among TSOs. As a result, the definitions of ordinary and exceptional contingencies can differ between TSOs. The standard allows for some variation in the categorization of contingencies, based on their likelihood and impact within a specific TSO network.

- An ordinary contingency is the (not unusual) loss of one of the following elements:
  - Generator.

[48] For all definitions, see also ENTSO-E's draft Operational Security Network Code (https://www.entsoe.eu/resources/network-codes/operational-security/)

- Transmission circuit (overhead, underground or mixed).
- A single transmission transformer or two transformers connected to the same bay.
- Shunt device (i.e. capacitors, reactors, ...).
- Single DC circuit.
- Network equipment for load flow control (phase shifter, FACTS, …).
- A line with two or more circuits on the same towers if a TSO considers this appropriate and includes this contingency in its normal system planning

- An exceptional contingency is the (unusual) loss of one of the following elements:
  - A line with two or more circuits on the same towers if a TSO considers this appropriate and does not include this contingency in its normal system planning
  - A single busbar.
  - A common mode failure with the loss of more than one generating unit or plant.
  - A common mode failure with the loss of more than one DC link.
- An out-of-range contingency includes the (very unusual) loss of one of the following:
  - Two lines independently and simultaneously.
  - A total substation with more than one busbar.
  - Loss of more than one generation unit independently.

D.3. **N-1 criterion for grid planning.** The N-1 security criterion is satisfied if the network is within acceptable limits for expected transmission and supply situations as defined by the planning cases, following a temporary (or permanent) outage of one of the elements of the ordinary contingency list (see D2 and chapter 4.2.2).

4.2. Common criteria

4.2.1 Studies to be performed

C.1. **Load flow analysis**

- **Examination of ordinary contingencies.** N-1 criterion is systematically assessed taking into account each single ordinary contingency of one of the elements mentioned above.
- **Examination of exceptional contingencies.** Exceptional contingencies are assessed in order to prevent serious interruption of supply within a wide-spread area. This kind of assessment is done for specific cases based on the probability of occurrence and/or based on the severity of the consequences.
- **Examination of out-of-range contingencies.** Out-of-range contingencies are very rarely assessed at the planning stage. Their consequences are minimized through Defence Plans.

C.2. **Short circuit** analysis. Maximum and minimum symmetrical and single-phase short-circuit currents are evaluated according to the IEC 60 909, in every bus of the transmission network

C.3. **Voltage collapse.** Analysis of cases with a further demand increase by a certain percentage above the peak demand value is undertaken. The resulting voltage profile, reactive power reserves, and transformer tap positions are calculated.

C.4. **Stability analysis.** Transient simulations and other detailed analysis oriented to identifying possible instability shall be performed only in cases where problems with stability can be expected, based on TSO knowledge.

4.2.2 Criteria for assessing consequences

C.5. **Steady state criteria**

- **Cascade tripping.** A single contingency must not result in any cascade tripping that may lead to a serious interruption of supply within a wide-spread area (e.g. further tripping due to system protection schemes after the tripping of the primarily failed element).
- **Maximum permissible thermal load.** The base case and the case of failure must not result in an excess of the permitted rating of the network equipment. Taking into account duration, short term overload capability can be considered, but only assuming that the overloads can be eliminated by operational countermeasures within the defined time interval, and do not cause a threat to safe operation.
- **Maximum and minimum voltage levels.** The base case and the case of failure shall not result in a voltage collapse, nor in a permanent shortfall of the minimum voltage level of the transmission grid, which are needed to ensure acceptable voltage levels in the sub-transmission grid. The base case and the case of failure shall not result in an excess of the maximum admissible voltage level of the transmission grids defined by equipment ratings and national regulation, taking into account duration.

C.6. **Maximum loss of load or generation** should not exceed the active power frequency response available for each synchronous area.

C.7. **Short circuit criteria.** The rating of equipment shall not be exceeded to be able to withstand both the initial symmetrical and single-phase short-circuit current (e.g. the make rating) when energizing on to a fault and the short circuit current at the point of arc extinction (e.g. the break rating). Minimum short-circuit currents must be assessed in particular in busbars where a HVDC installation is connected in order to check that it works properly.

C.8. **Voltage collapse criteria.** The reactive power output of generators and compensation equipment in the area should not exceed their continuous rating, taking into account transformer tap ranges. In addition the generator terminal voltage shall not exceed its admissible range.

C.9. **Stability criteria.** Taking into account the definitions and classifications of stability phenomena[49], the objective of stability analysis is the rotor angle stability, frequency stability and voltage stability in case of ordinary contingencies (see section 3.1), i.e. incidents which are specifically foreseen in the planning and operation of the system..

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[49] Definition and Classification of Power System Stability, IEEE/CIGRE Joint Task Force, June 2003

- **Transient stability.** Any 3-phase short circuits successfully cleared shall not result in the loss of the rotor angle and the disconnection of the generation unit (unless the protection scheme requires the disconnection of a generation unit from the grid).
- **Small Disturbance Angle Stability**. Possible phase swinging and power oscillations (e.g. triggered by switching operation) in the transmission grid shall not result in poorly damped or even un-damped power oscillations.
- **Voltage security**. Ordinary contingencies (including loss of reactive power in-feed) must not lead to violation of the admissible voltage range that is specified by the respective TSO (generally 0.95 p.u. – 1.05 p.u.)

4.3. Best practice

R1. **Load flow analysis. Failures combined with maintenance.** Certain combinations of possible failures and non-availabilities of transmission elements may be considered in some occasions. Maintenance related non-availability of one element combined with a failure of another one may be assessed. Such investigations are done by the TSO based on the probability of occurrence and/or based on the severity of the consequences, and are of particular relevance for network equipment that may be unavailable for a considerable period of time due to a failure, maintenance, overhaul (for instance cables or transformers) or during major constructions.

R2. **Steady state analysis.** Acceptable consequences depend on the type of event that is assessed. In the case of exceptional contingencies, acceptable consequences can be defined regarding the scale of the incident, and include loss of demand. Angular differences should be assessed to ensure that circuit breakers can re-close without imposing unacceptable step changes on local generators.

R3. **Voltage Collapse analysis:** The aim of voltage collapse analysis is to give some confidence that there is sufficient margin to the point of system collapse in the analyzed case to allow for some uncertainty in future levels of demand and generation.

End note.

System development tools are continuingly evolving, and it is the intention that this document will be reviewed periodically in line with prudent planning practice and further editions of the TYNDP.

Annex 1 : IMPACT ON MARKET POWER

Context

The Energy Infrastructure Package project requires that the CBA takes into account the impact of the infrastructure on market power in the 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 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)/(remedies) will be assessed. The calculus of the index will be made with and without this object, and the difference on this two calculus 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 requires choosing an index among existing possibilities, such as Residual Supply Index (RSI) or Herfindahl-Hirschman Index (HHI). Each of these has its advantages and disadvantages ;

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, monetization 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 classically performed by evaluating the impact of a project during its whole life cycle. This requires to make a complete set of hypothesis on the future, for instance on the evolution of the level of consumption. Unfortunately, **market power evolution cannot be modeled**, 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 infrastructures may have a positive impact on market power issues, but it is not the only solution. One should note that **an infrastructure project takes more time to complete is more costly than a decision affecting regulation/competition**. In case a market power issue is identified in a Member State, the national regulator should undertake relevant actions to force market players to respect the rules, rather than trying to solve the problem by expanding the infrastructure. Indeed, regulatory solutions are much more adapted to such an issue.

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 infrastructure. **This is all the more important considering that there are other, faster ways to solve market power issues: through regulation**. By the time a project is completed, it is very likely that the market power issue has already been tackled by the regulator, and the infrastructure 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 vision 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.

ANNEX 2: MULTI-CRITERIA ANALYSIS VS 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 (representing EU energy policy, as outlined by the criteria specified in annexes IV and V of the draft Regulation) should be included in the assessment framework,
- Credibility/opposability : if a criterion is weighted, the unit value must stem from an external and credible source (international or European reference)
- Coherence: if a criterion is weighted, the unit value must be coherent within the area under consideration (Europe or Regional Group).

The limits of a « pure » cost benefit analysis

- A single criterion provides less information (and is less transparent) then a multi-criteria balance sheet. Moreover, it is not well adapted in the case of multi-actor governance, such as the one foreseen by the EIP Regulation, where the actors will need information on each of the criteria in order to take common decisions.
- A « pure « CBA cannot cover all criteria specified in annexes IV and V of the EIP Regulation, since some of the benefits are difficult to monetize.
    - 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, such as, "operational flexibility », have no opposable monetary value today (they qualify robustness and flexibility rather than a quantifiable economic value) ;
    - Some benefits have opposable values at a national level, but no common value exists in Europe. This is case with, for instance, the value of lost load, 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 internalized (e.g. in socio-economic welfare). Displaying a value in tons provides additional information and prevents double accounting.

As stated in the EC Guide to Cost Benefit Analysis (2008): "In contrast to CBA, which focuses on a unique criterion (the maximization 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" ; "Multi-criteria analysis, i.e. multi-objective analysis, can be helpful when some objectives are intractable in other ways and should be seen as a complement to CBA ».

This is why ENTSO-E favors 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 Europe-wide level. This approach allows for a homogenous assessment of projects on all criteria (e.g. MWh RES is the priority of the region is RES integration).

ANNEX 3 : TOTAL SURPLUS ANALYSIS

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.

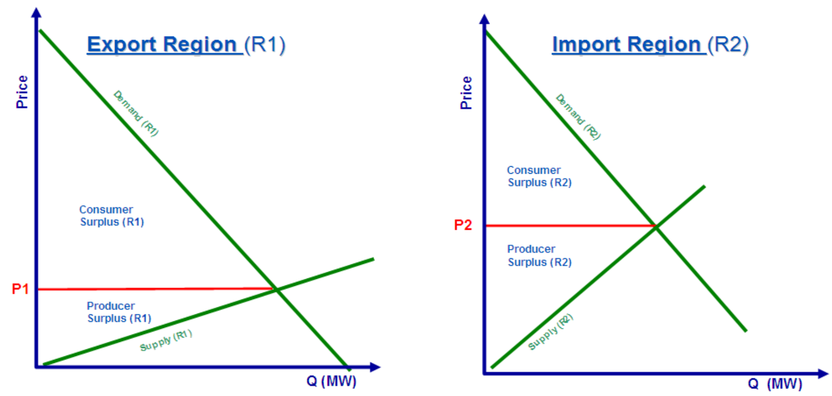

Figure 3.1: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity (elastic demand)

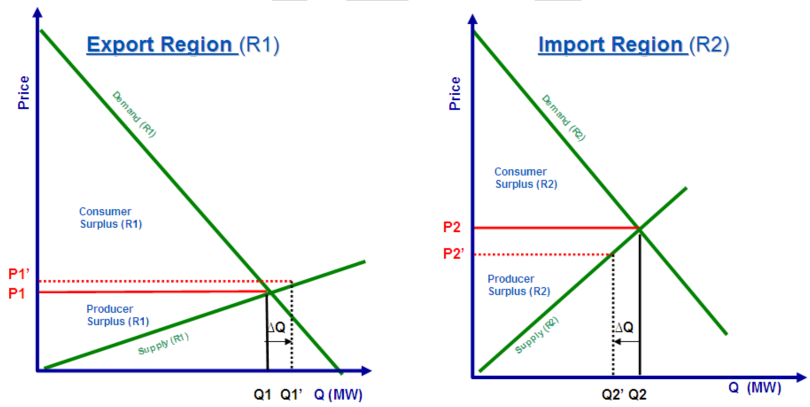

Figure 3.2: Example of an export region and an import region, with a new project increasing the GTC between the two regions (elastic demand)

The 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 hours of the year.

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**[50] can be calculated as follows:

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

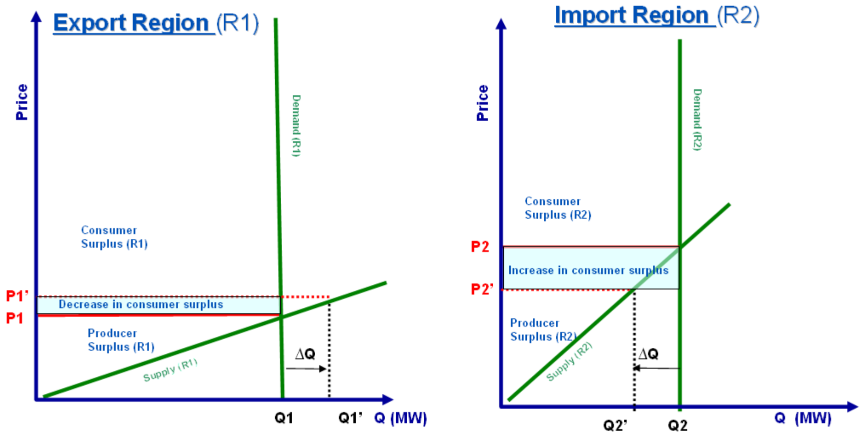

Figure 3.3: Change in consumer surplus

The change in **producer surplus**[51] can be calculated as follows:

Change in **producer surplus** = generation revenues – generation costs

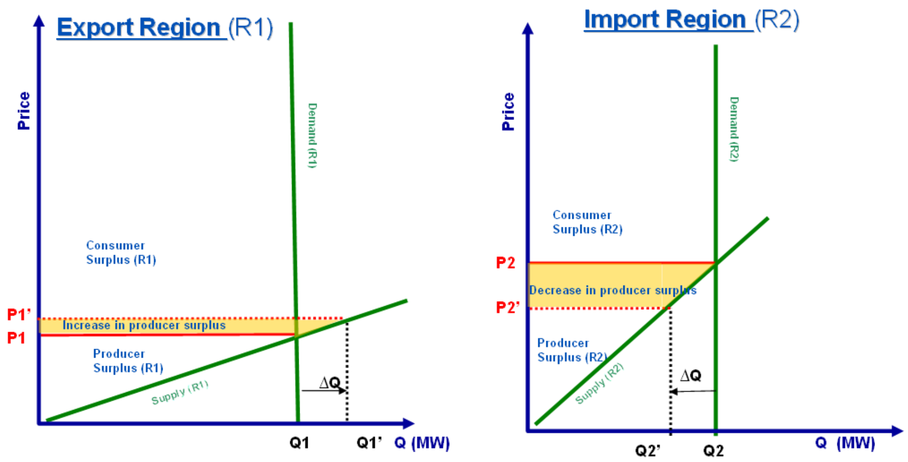

Figure 3.4: Change in producer surplus

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50 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)*$_{\textit{with the project}}$ – *marginal cost of the area x total consumption of the area)*$_{\textit{without the project}}$

51 Generation revenues equal: *(marginal cost of the area x total production of the area).*

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[52].

The change in **total congestion rent** can be calculated as follows:

Change in **total congestion rent** = change of congestion rents on all links between import and export areas

52 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

ANNEX 4 CROSS REFERENCES REQUIREMENTS REGULATION AND CHAPTERS OF THIS DOCUMENT

Category	Annex IV	Annex V	Guideline ENTSO-E
Market integration, competition and system flexibility	(2a) for cross-border projects, the impact on the grid transfer capability in both power flow directions, measured in terms of amount of power (in megawatt), or, for projects with significant cross-border impact, the impact on grid transfer capability at borders between relevant Member States, between relevant Member States and third countries or within relevant Member States ***MW*** and on demand-supply balancing and network operations in relevant Member States		**Grid Transfer Capability (GTC)** reflects the ability of the grid to transport electricity across a boundary, i.e. from one area (price zone, area within a country or a TSO) to another. It depends on the considered state of consumption, generation and exchange, as well as the topology and availability of the grid. The GTC is oriented, i.e. there may be two different values depending on the direction of the power flow across a boundary. ***MW*** **B1 Improved security of supply**: the ability of a power system to provide an adequate and secure supply of electricity in normal conditions. ***MWh***
	(2a) assessing the impact, for the area of analysis as defined in point 10 of Annex V, in terms of energy system-wide generation and transmission costs and evolution of market prices provided by a project under different planning scenarios, notably taking into account the variations induced on the merit order. ***€***	(6a) Competition in terms of market power of different operators; (6b) Costs of electricity generation, transmission and distribution, including the costs for power plant self consumption and those related to greenhouse gas emissions and transmission losses over the technical lifecycle of the project; ***€***	*Annex 1* **B2. Socio-economic welfare:** the ability of a power system to reduce congestion and thus provide an adequate GTC. ***€ (calculated, published in 3 level color code)*** **B4. Variation in losses** in the transmission grid is the characterization of the evolution of thermal losses in the power system. It is an indicator of energy efficiency. ***€*** **B5. Variation in CO2 emissions** is the

		(6c) Future costs for new generation and transmission investment over the technical lifecycle of the project; **€**	characterization of the evolution of CO2 emissions in the power system. It is a result of B2 (unlock of generation with lower carbon content) and B4 (variations in losses). ***tons*** **B2. Socio-economic welfare** + calculation of residual value in order to take into account the costs over the technical lifecycle of the project
Transmission of renewable energy generation to major consumption centres and storage sites	**(2b)** for electricity transmission, by estimating the amount of generation capacity from renewable energy sources (by technology, **in megawatts**), which is connected and transmitted due to the project, compared to the amount of planned total generation capacity from these types of renewable energy sources in the concerned Member State in 2020 according to the national renewable energy action plans as defined in Article 4 of Directive 2009/28/EC.		**B3. RES integration** The ability of the system to allow the connection of new RES plants or unlock existing "green" generation (minimize curtailments) ***MW/MWh***
Interoperability and secure system operation	(2c) assessing the impact of the project on the loss of load expectation for the area of analysis as defined in point 10 of Annex V in	(6d) Operational flexibility, including optimisation of regulating power and ancillary services;	**B1 Improved security of supply**: the ability of a power system to provide an adequate and secure supply of electricity in normal conditions. ***MWh***

	terms of generation and transmission adequacy for a set of characteristic load periods, taking into account expected changes in climate-related extreme weather events and their impact on infrastructure resilience.	(6e) System resilience, including disaster and climate resilience, and system security, notably for European critical infrastructures as defined in Directive 2008/114/EC.	+ **B7 Flexibility** the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios, including trading of balancing services ***+/- (estimated, published in 3 level color code)*** **B6 Technical resilience/system safety :** the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies) ***+/- (estimated, published in 3 level color code)***
The **Project impact on society**			**Social and Environmental sensibility** characterizes the project impact as perceived by the local population and assessed through preliminary studies, and as such, gives a measure of probability that the project will be built at the planned commissioning date. ***+/- (estimated, published in 3 level color code)***
Benefits, calculation method		(9) The methodology shall define the analysis to be carried out, based on the relevant input data set, by calculating the results of the objective function with and without each project. The analysis shall identify the Member States on which the project has net positive impacts (beneficiaries) and those Member States on which the project has a net negative impact (cost bearers). Each cost-benefit analysis shall include	The assessment framework is a multi-criteria one. The evaluation of effects may be performed using both, market studies and network analysis, as well as expert assessment. Only total welfare is calculated in a systematic way. Benefit per MS will be calculated when needed. **B7 Flexibility**

		sensitivity analyses concerning the input data set, the commissioning date of different projects in the same area of analysis and other relevant parameters.	the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios, including trading of balancing services
Benefits, calculation method		(12) full assessment of economic, social and environmental impacts, notably including external costs such as those related to greenhouse gas and conventional air pollutant emissions or security of supply.	**B1-B7**
Costs, calculation method	(2) The total expenditure for the project over its technical lifecycle shall be taken into account when calculating these indicators.	(5) The cost-benefit analysis shall at least take into account the following costs: capital expenditure, operational and maintenance expenditure over the technical lifecycle of the project and decommissioning and waste management costs, where relevant. The methodology shall give guidance on discount rates to be used for the calculations.	**Total project expenditures** are based on prices used within each TSO and rough estimates on project consistency (e.g.: km of lines…). Land costs, costs of obtaining permissions, and cost of damages must be considered as variables between TSOs. The project cost should consider life cycle costs. Costs have to be estimated for each project. Within ENTSO-E, project expenditures are strongly dependent on local conditions and therefore differ. Consequently, project costs may be calculated using local standard-cost. Residual value is calculated in order to take into account the costs over the technical lifecycle of the project (4.4) Guidance on discount rates is given (see section 4.3.3).