DEVELOPING A REGULATORY GUIDE TO REVIEWING, APPROVING, AND MONITORING TEN-YEAR TRANSMISSION NETWORK DEVELOPMENT PLANS

(SOUTHEAST EUROPE ELECTRICITY REGULATORS)

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TASK 6B. FINAL GUIDE TO REVIEWING, APPROVING, AND MONITORING TEN-YEAR TRANSMISSION NETWORK DEVELOPMENT PLANS

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Contents

List of Acronyms

ACER	Agency for the Cooperation of Energy Regulators
AHP	Analytical Hierarchy Process
AIT	Average Interruption Time
CAPEX	Investment (Capital) Cost
CBA	Cost-Benefit Analysis
CBCA	Cross-Border Cost Allocation
CEER	Council of European Energy Regulators
DSO	Distribution System Operator
EC	European Commission
EDR	Economic Discount Rate
EMF	Electric and Magnetic Fields
ENPV	Economic Net Present Value
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ERR	Economic Rate of Return
EU	European Union
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GTC	Grid Transfer Capability
IFI	International Financing Institutions
IPA	Instrument for Pre-Accession Assistance
IRP	Integrated Resource Planning
ISO	Independent System Operator
MCA	Multicriteria Analysis
NARUC	National Association of Regulatory Utility Commissioners
NGO	Non-Governmental Organization
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
O&M	Operation and Maintenance
OPGW	Optical Ground Wiring
PCI	Projects of Common Interest
PINT	Put One In at a Time
PV	Present Value
RES	Renewable Energy Sources
SCADA	System Control and Data Acquisition
SDR	Social Discount Rate
SEW	Socioeconomic Welfare
SoS	Security of Supply
TOOT	Take One Out at a Time
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VoLL	Value of Lost Load

1. Context and Purpose of the Guide

As signatories to the Energy Community Treaty, countries in Southeast Europe require their transmission system operators (TSOs) to develop ten-year network development plans (TYNDPs) in accordance with the European Union's Third Energy Package, including Directive 2009/72/EC concerning common rules for the internal market in electricity (Article 22 on network development and powers to make investment decisions). This requirement directs TSOs to model their current transmission networks and to forecast necessary upgrades and investments in the system with the help of simulation software.

National Regulatory Authorities (NRAs or Regulatory Authorities) are responsible for reviewing and approving plans developed by TSOs, in accordance to the national strategy, and thereafter monitoring the approved plans to ensure that TSOs are following the investments outlined. Southeast Europe NRAs could greatly benefit from assistance in informing TSOs on what is expected of their plans, evaluating the cost-benefit proposition and prudency of the investments, as well as monitoring the investments and service quality indicators once the plans have been approved.

In this context, the U.S. National Association of Regulatory Utility Commissioners (NARUC) has contracted a consultant to develop the capacity of Southeast Europe NRAs, in particular the Albanian Energy Regulator, State Electricity Regulatory Commission, Regulatory Commission for Energy in the Federation of Bosnia and Herzegovina, Regulatory Commission for Energy of Republic of Srpska, Georgian National Energy and Water Regulatory Commission, Energy Regulatory Office, Energy Regulatory Commission, Energy Regulatory Agency, and Energy Agency of the Republic of Serbia, to understand, review, approve, and monitor TYNDPs.

The aim of this document is to provide NRAs with a guide for **conducting appraisals of electricity TYNDPs and for the investment projects included in TYNDPs.** The guide is composed of a comprehensive toolbox for appraising and monitoring electricity transmission development plans and projects, and it includes a step-by-step approach as well as checklists to help the NRAs. It provides a comprehensive and useful framework that NRAs can use and adapt to develop tailor-made national methodologies for electricity TYNDPs and project appraisals.

1.1 Contents of the Guide

Following this introduction, Section 2 discusses the role of NRAs regarding the appraisal of the TYNDP and constituent projects. Section 3 **recommends** TSOs prepare TYNDPs using a uniform structure. The methodology and modeling steps in developing TYNDPs are presented in Section 4. This is followed by Section 5, which discusses the approach to reviewing the development assumptions for TYNDPs. Section 6 provides the rationale for allocating electricity transmission investment projects into different categories, the project categories recommended, and differences in the appraisal approach between these. It also presents the information required to demonstrate the rationale and justification for the TYNDP projects. Section 7 describes the basic principles and techniques for conducting an economic cost-benefit analysis (CBA) of investment projects. Section 8 subsequently provides a discussion on the proposed risk and sensitivity analysis to accompany economic assessments. Section 9 discusses the determinants and actions for the development and facilitation of a regional approach to electricity transmission project planning. Section 10 examines the need for project prioritization and the different options for prioritizing projects that NRAs should review and appraise. It also assesses the overall impacts from each TYNDP. Section 11 provides a discussion on stakeholder and public consultation, followed by the presentation of approved electricity transmission investments to the general public in Section 12. Finally, Section 13 discusses the approach to monitoring TYNDP implementation.

Cybersecurity is a particular and internationally emerging concern related to the increase in automatically controlled electricity networks, and, as such, is prominently considered throughout all sections of this guide. Cybersecurity can be addressed by the TSOs through information security policies, certification according to ISO 27001 on information security management or ISO 27019 on energy sector process control management, risk management tools (e.g., the Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) specifically for the electricity sector), other proactive measures, or a combination of the above. Internationally, TSOs are appointing cybersecurity managers or teams to initially countersign the TYNDPs, thus verifying their development using risk management principles for identifying vulnerabilities and mitigating cyber threats, and subsequently implementing cybersecurity requirements as they are included in national legislation.

However, it is important to note that careful consideration should be given to cybersecurity-related information presented in the TYNDPs because of the sensitive nature of the information. It is **recommended** that the TSOs and NRAs seek further guidance on cybersecurity policies regarding energy and other infrastructure elements, as provided in NARUC's related Cybersecurity Primer for State Utility Regulators[1] and other dedicated documents. The Council of European Energy Regulators (CEER) has recently issued a report with recommendations on cybersecurity,[2] including a more proactive role for NRAs in establishing a cybersecurity culture among their regulated entities. Further, given the need for general treatment of cybersecurity in all TYNDP projects, specific projects of primary information technology and cybersecurity may also be included in the TYNDP (e.g., system control and data acquisition, SCADA, software for system surveillance, optical ground wiring, OPGW, etc.).

Each of the regulatory assessment Sections (4–13) leads to a **recommended** checklist on the issues that NRAs should address and decide upon in building their national methodology for reviewing electricity TYNDPs and constituent projects.

1.2 How to Use the Guide

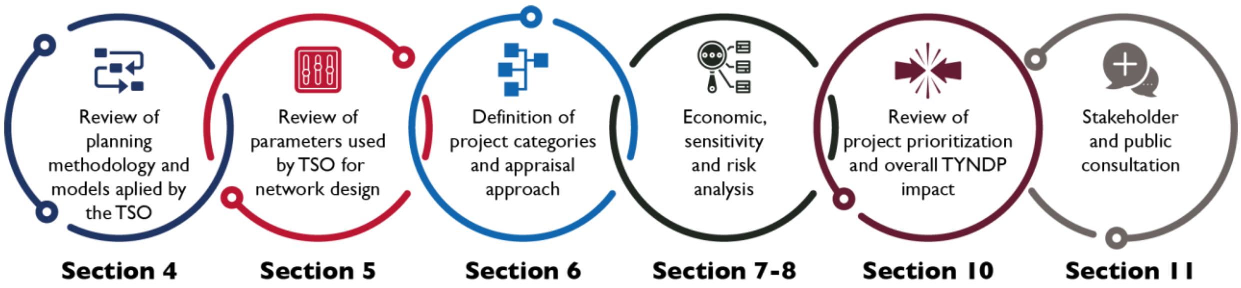
Each of the remaining sections of this guide is dedicated to discussing the components of the regulatory review and appraisal process of the TYNDP and its constituent projects, and to providing potential approaches that NRAs could adopt in their appraisal process. The "shopping list" of things to do is often in maximalist form, in the sense that this guide documents the maximum analysis that could be requested or applied for TYNDP project appraisal. It is up to each NRA to modify the approaches so that the guide is more tailored to national needs (e.g., by determining the categories of projects in the TYNDP and how each category will be appraised, by specifying budget thresholds above which CBA would be required, by determining which project benefits will be monetized, by deciding how project prioritization will take place, etc.).

Figure 1 provides an overview of the tasks that the NRA should undertake to perform a complete appraisal of an electricity TYNDP.

[1] "Cybersecurity Primer for State Utility Regulators, Version 3.0." NARUC. 2017. https://pubs.naruc.org/pub/66D17AE4-A46F-B543-58EF-68B04E8B180F

[2] "Cybersecurity Report on Europe's Electricity and Gas Sectors." CEER. October 2018. https://www.ceer.eu/documents/104400/-/-/684d4504-b53e-aa46-c7ca-949a3d296124

Appraisal Figure 1. Overview of Electricity TYNDP Appraisal Tasks



2. Role of Regulatory Authorities in the Appraisal of TYNDPs

This guide provides a general framework for review and appraisal of TYNDPs and constituent projects, likened to an exhaustive shopping list of tasks that could be undertaken by NRAs in the course of their review and appraisal of TYNDPs. Nevertheless, in developing the national investment plan appraisal methodology, each NRA may opt for a different scope and depth of the review and appraisal, depending on the legal mandate that each NRA has concerning TYNDPs, that is, whether the NRA is simply enabled to review and pass an opinion on the TYNDP, or whether the NRA is empowered to approve/amend the TYNDP. Different mandates influence the breadth and depth of review and appraisal that NRAs opt to adopt.

Furthermore, the regime assumed in this guide is that of regulated investments, that is, a regime encompassing mainly the following:

- TSO drafts the TYNDP, taking into account proposals by network users;
- NRA approves the TYNDP;
- TSO is responsible for the construction of individual facilities (in addition, construction/operation/transfer contracts may be competitively procured); and
- Recovery of (efficient) capital and operation and maintenance (O&M) costs guaranteed through regulated access and use-of-system charges.

The approach described in Directive 2009/72/EC of the European Parliament and of the Council concerning common rules for the internal (EU) market in electricity provides a set of principles that EU NRAs have to follow during the evaluation and/or approval process of the TYNDP:

- Consult all actual or potential system users on the TYNDP in an open and transparent manner and publish the result of the consultation process, in particular, possible needs for investments;
- Examine whether the TYNDP covers all investment needs identified during the consultation process;
- Require the TSO to amend the TYNDP; and
- Monitor and evaluate the implementation of the TYNDP.

While in the process of developing an opinion or approval of a TYNDP, the NRA may require specific amendments to ensure that the needs of the transmission network users are covered to a sufficient extent and that the national policies (e.g., security and quality of supply, electricity market facilitation and cross-border trade, and environmental objectives related to the electricity transmission network) are met at a reasonable cost. In case the NRA decides not to approve the submitted TYNDP and to ask the TSO for amendments, appropriate justification should be included in the respective regulatory decision. For example, if the NRA's judgment is that users' needs for transmission were not fully taken into account, the respective decision of the NRA should depict cases in which some needs of transmission raised by potential users are not taken into account in the TYNDP and no reason is provided for this in the TYNDP.

In parallel with the above, a TYNDP has to be feasible from a financial point of view. Thus, the TSO has to provide, and the NRA has to check (and eventually approve), an analysis of the expected level of expenses required for implementation of the TYNDP, as well as potential sources of income and financing of the proposed investments. Project sequencing and prioritization, to take into account budgetary and other constraints of the TSO, is discussed in more detail in Section 10.1 of the guide.

Toward the above objectives, the NRA may issue (or require the TSO to develop for the NRA to approve) rules, methodologies, and guidelines on topics relevant to the TYNDP development process such as:

- transmission network codes;
- transmission planning standards and regulations;
- economic (cost-benefit) analysis of transmission projects; and
- reference costs of transmission network equipment.

In general, it is **recommended** when assessing TYNDPs that NRAs check modeling results at a high level and not try to duplicate the respective studies performed by the TSOs. Toward this objective, NRAs should:

- Ask for detailed results/outputs of the models (market, network);
- Ask for explanations in case some result(s) appear to be erroneous or not evident;
- Use common thinking and reasoning; and
- Obtain support from external experts in case significant technical issues are involved in the justification of a project.

Developing in-house expertise for studies performed by the TSO (e.g., market and network studies—especially network studies) is not recommended, as in this case, the body assessing the TYNDP would tend to substitute the TSO in its task.

NRAs can also use external expertise for the assessment of TYNDP projects. Recently in Greece a technical task force was formed (with experts from the TSO, the electric utility, and the NRA) to undertake a detailed feasibility study for the key project of interconnecting the island of Crete to the mainland Greek transmission system. Following the positive results of this feasibility study (which included a CBA), the Greek TSO introduced a detailed proposal for the Crete interconnection in the TYNDP.

The legal mandate of the NRA in relation to TYNDP appraisal, the role that an NRA adopts in exercising its mandate, and the specific appraisal framework that the NRA will select from a range of options, the most important of which are highlighted in this generic guide, define the national methodology/guide for TYNDP appraisal.

Finally, it is important that the NRA continuously strives toward defining and refining a set of responsibilities and incentives to lead to efficient transmission network expansion. This would facilitate the appraisal of the TYNDP since such a regime would presumably encompass a regulatory framework to align the cost-benefit assessment by the TSO to social welfare. This may be achieved by establishing an appropriate unbundling framework for the TSO combined with: (i) quality standards and financial incentives (e.g., allowance of increased return on investment for specific projects) to avoid under-investment and (ii) project scrutiny (e.g., through CBA) to mitigate trends for over-investment.

3. Structure and Contents of the TYNDP

This section proposes an appropriate uniform structure for the TYNDPs. The level of information and analysis that must be provided in the TYNDPs is referred to in the remaining sections.

Taking into consideration Directive 2009/72/EC concerning common rules for the internal market in electricity (Article 22 on network development and powers to make investment decisions), as well as TYNDPs prepared in the EU (United Kingdom, Ireland, France, Sweden, Greece, Slovenia, etc.) and other developed countries (Canada, Australia, South Africa, etc.), the following uniform structure for TYNDPs in the Southeast European countries is **recommended**:

1. Context and Purpose of the TYNDP;
2. Approach, Methodology, Planning Standards, and Criteria;
3. TSO Characteristics, Network, Weak Elements, Challenges, and Opportunities;
4. Implemented Elements of Previous TYNDP;
5. Future Energy Demand and Generation Scenarios (including renewable energy and market integration);
6. Current Network Simulation and Planning Assumptions;
7. Vision and Investment Drivers for Network Development;
8. Planned Network Developments, Time-Plan, Cost Analysis, and Benefits;
9. Cost-Benefit, Risk, and Sensitivity Analysis; and
10. Detailed Analysis Annex (technical studies, project development stages, etc.).

This TYNDP structure is hereafter referenced throughout the remaining sections of this guide, in the final **recommended** checklists on issues that NRAs should assess and systematically appraise, as well as other instances to identify the location of information under review.

4. Methodology and Modeling Approach

The methodology and modeling steps in developing TYNDPs are presented next, followed by a checklist for their appraisal by NRAs.

4.1 TYNDP Development Approach

A series of steps that can be followed by TSOs in the TYNDP development process are proposed next. These can be modified or condensed depending on the experience of the TSO and availability of modeling tools, as well as the size and special characteristics of the system under consideration.

1. Description of current national situation and prospects: This step includes a description of the current situation of the country in terms of economic growth, energy conditions and environmental constraints, and targets related to the power system, as well as the evolution prospects for these issues in the next 5 to 10 years. Examples of documents to be consulted may include the National Development Strategy, Distribution System Operator (DSO) development plan, regional economic development plans, and so on. Furthermore, the pan-European TYNDP of the European Network of Transmission System Operators for Electricity (ENTSO-E) and the Energy Community regulations regarding greenhouse gas (GHG) emissions, renewable energy sources (RES), market integration, and so on, should also be taken into consideration. This step includes a review of trends and policies for installing new generation, decommissioning of existing plants, and recent developments and issues identified in the country's transmission network, as well as the progress from the previous TYNDP. Policies and targets for market liberalization and cross-border trading are also described. Finally, technical problems and challenges for the transmission network, observed since the elaboration of the previous TYNDP, are also described (e.g., voltage problems, congestion, etc.).

2. Demand analysis: This step deals with an analysis of the historical trend of electricity and peak load demand as well as prospects for the evolution of these parameters over the TYNDP planning horizon (e.g., 10 years).

3. Identification of TYNDP drivers: Based on the two previous steps, the main needs for availability of transmission capacity in the planning horizon are described. These would mainly stem from needs based on the overall strategy, concerning the evolution of the country's power system and an assessment of parameters such as:

- Security of supply (SoS) of electricity;
- System reliability (application of the N-1 or N-2 criteria);
- Provision of access (connection and operation) to new generators and loads;
- Interconnection of remote areas of the country, if applicable;
- Interconnection with neighboring systems or markets;
- Developing transmission infrastructure for the integration of RES; and
- Identified technical problems (level of voltages, congestion, etc.).

4. Development of planning scenarios: This step involves the development of scenarios concerning the main parameters characterized by uncertainty, which are influential in the transmission planning process:

A first set of scenarios deals with the evolution of the main parameters affecting the power system, such as economic growth, degree of development of interconnectors, degree of development of RES, and so on. Toward this objective, national public documents and/or TSO's predictions may be used. TSO's predictions are especially useful in case the TSO feels that the information available in the national documents or the official projections of competent ministries are outdated and/or do not reflect recent developments (e.g., do not reflect a sudden downturn of the economy) or are somehow biased upward, leading to results that might be considered wishful thinking. The TSOs should explain the reasons for using alternative (their own) forecasts to produce additional scenarios within a TYNDP.

Following the first set, a second set of scenarios is then produced, dealing with detailed (yearly) projections of the:

- Electricity and peak load demand; and
- Supply options, that is, installed generation capacity and energy availability from energy-limited sources (e.g., hydro) and from interconnectors.

Assumptions regarding uncertainty (economic growth, demand, RES, etc.) are important parts of the TYNDP and should be checked thoroughly by the NRA.

Based on the scenarios concerning the uncertainty parameters, sets of planning scenarios (or planning assumptions) are formed, each involving a set of values for all the uncertainty parameters.

5. For each planning scenario:

5.1. Identify transmission needs: For the target year (year 10 in the case of a TYNDP), transmission needs are identified. In the target year, all known and reasonably assumed generation and transmission investments should be considered as realized.

5.2. Initial screening/options analysis: This step aims to assess all promising strategic and technical alternatives based on physical circumstances and available technologies.

5.3. Development of target network: This step involves the design of the transmission network for the target year based on the analysis performed in the previous steps. The target network should approximate the network of minimum cost, which satisfies the requirements for transmission service at specified reliability (demand coverage, connection of generators, interconnection targets, N-1 or N-2 criteria, etc.). Depending on the TSO's practice and/or regulatory guidelines, the target network corresponds to a network able to accommodate the majority of requirements stemming from the demand/supply scenarios analyzed in the previous steps.

5.4. Generation system adequacy analysis: Based on the demand and supply scenarios developed in the previous steps, the generation system is analyzed (e.g., through deterministic or probabilistic simulation of operation) for each year of the 10-year planning horizon. Such analysis might follow hourly or weekly steps using a copper plate approach (i.e., neglecting transmission) to determine the degree to which the assumed generation capacity and energy from energy limited sources, in conjunction with contribution from cross-border interconnectors, meet the assumed load demand at the specified level of reliability (deterministic or probabilistic). The output of this step is, for each scenario, a generation system with the necessary installed capacity that covers the assumed demand at the specified reliability level.

Depending on the methodology used, time series or probability functions of electricity from intermittent RES (e.g., wind, solar, run-of-river hydro) must be available for this step.

5.5. Dispatch simulation analysis of the generation system: This step provides information about the expected loading behavior of the generation system to help identify potential stress hours of operation of the power system during which the transmission network has to perform adequately. Usually this involves hourly simulation of the operation of the power system for the 8,760 hours or at selected hours (e.g., hours of peak demand) during the study year (e.g., the 5th and the 10th year of the 10-year planning horizon). Technical constraints of generation units (e.g., ramping, up/down time) and, where applicable, network constraints, are modeled in this step. Transmission system constraints (e.g., thermal limits) may also be incorporated/modeled during this step. The output of this step provides the loading of generation units during the specific hours of analysis so that analysis of the transmission network can be performed in the next step.

5.6. Network analysis: This step involves the technical studies (network studies) for the target network developed in step 5.3. Depending on the results of the analysis, necessary interventions (projects) are identified and further examined for the purpose of network reinforcement to eliminate any problems and violations of the planning criteria detected during this iterative process. In case more than one investment is identified for the purpose of solving an identified violation or problem, an economic CBA is conducted according to the next step (6), so that a winner is chosen for each set of examined alternatives.

The technical studies to be performed in this step include:

- load flow studies for voltage and transmission loss evaluations;
- contingency load flow analysis to check whether reliability criteria are met;
- short-circuit analysis to verify that existing or new breakers will be able to interrupt faults within their ratings; and
- stability analysis.

5.7. Identification of necessary projects: The above process provides a set of necessary projects for each planning scenario.

6. TYNDP project selection and CBA: Assess if certain projects are needed in most of the scenarios (*robust projects*) and include those in the TYNDP. Then include in the TYNDP the projects appearing as necessary in the TSO's preferred planning scenario (*preferred projects*); some TSOs tend to use the worst-case scenario for this purpose. If after following the above process, it is not obvious whether a project should be included in the TYNDP because the same purpose/objective is served by more than one project (*competing projects*), it is **recommended** to conduct an economic CBA. A CBA is also **recommended** for all *major projects* (e.g., interconnectors); for a discussion on the definition of major projects, please refer to Section 7.1. (A flow diagram is presented in Figure 3 that depicts the proposed steps that can be followed by TSOs when deciding whether to perform CBA.)

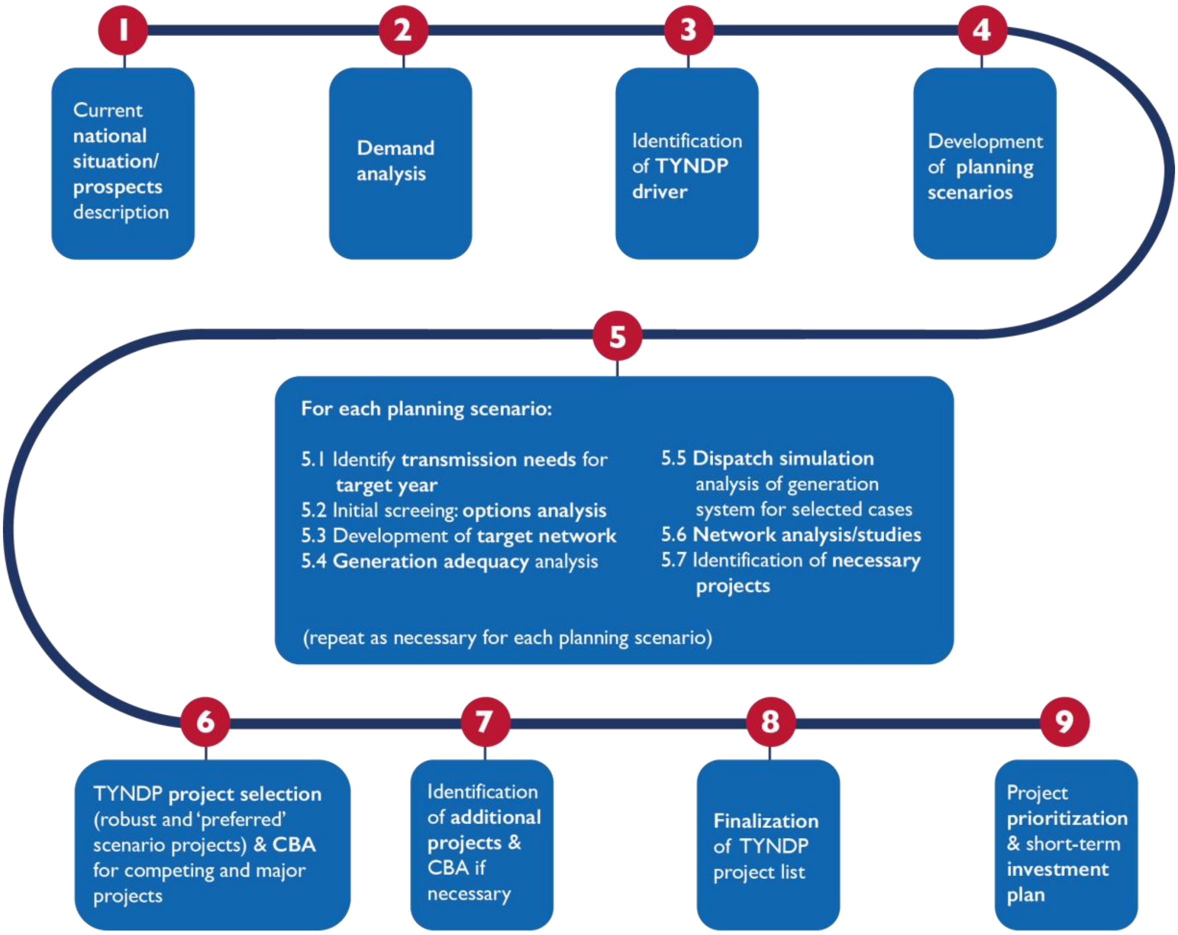
7. Identification of additional projects: Regarding the above-described *necessary projects*, the TSO should examine and propose investments that increase the economic efficiency of the transmission network (*efficient projects*). In this category, there may be projects that reduce transmission losses or connect non-interconnected regions. An economic CBA should always accompany such proposals, as presented in the flow diagram in Figure 3.

8. Finalization of TYNDP project list: This step involves consolidation of the projects resulting from steps 6 and 7 to be included in the TYNDP.

9. Project prioritization and short-term investment plan: This step involves prioritization of projects, especially in case of budget or other resource constraints, and reflecting strategic priorities. A short-term (e.g., 3 years) investment plan is developed.

Figure 2 summarizes these proposed steps.

Figure 2. TYNDP Development Process



Additionally, the following considerations/elements should be considered when developing the TYNDP:

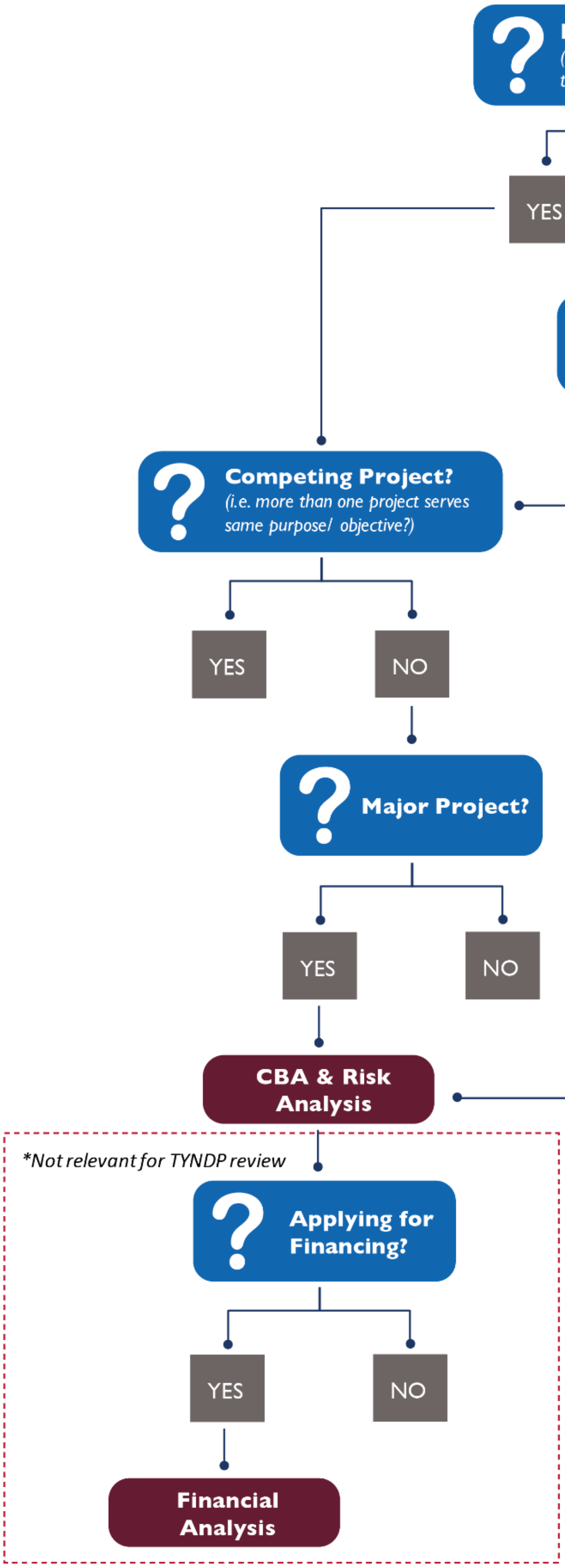
For competing and major projects

A. Available connection capacity at specific points or areas of the transmission network: The TYNDP should provide to prospective users (e.g., potential generators from RES) the capacity of the network to accommodate injections at specific locations.

B. Time plan and cost: The TYNDP should include summary tables with all transmission projects identified in the previous steps, their main phases, and timeline for implementation, as well as a cost estimate (which would enable benchmarking with other similar projects in the same or other countries). Implementation of this time plan depends on a more detailed assessment of the potential evolution of the respective parameters of the power system (progress of construction of new plants, evolution of demand, etc.).

In steps 6 and 7 of the TYNDP development process, CBA is proposed as an analytical tool to support the selection of projects for inclusion in the TYNDP. In Figure 3, a flow diagram is presented that depicts in detail the proposed steps that can be followed by TSOs, under steps 6 and 7 of the TYNDP development process, to decide whether to perform CBA (discussed in detail in Section 7) and risk analysis (discussed in detail in Section 8) for a specific project, as well as financial analysis pertaining to projects that are applying to donors, international financing institutions (IFIs), and/or ministries for financing.

Figure 3. Approach to Deciding Whether to Perform CBA and Risk Analysis and/or Financial Analysis



4.2 Checklist for Regulatory Appraisal

The NRA must verify the methodology and modeling approach developed in each TYNDP (in Section 2 of the recommended structure). Significant areas for systematic appraisal are:

1. Description of planning standards;
2. Adequate description of the drivers for transmission capacity;
3. Provision of forecasts for the main uncertainty parameters in the target year;
4. Planning scenarios to be analyzed;
5. Provision of an adequate generation system for the target year;
6. Results of technical studies;
7. Results of CBA for major projects;
8. Robust projects across planning scenarios;
9. TSO's preferred planning scenario; and
10. Short-term (e.g., 3-year horizon) investment plan.

5. Network Development and Planning Assumptions

The approach to assessing the network development and planning assumptions for TYNDPs is presented in this section as it relates to demand, supply, and system-wide data assumptions as well as global infrastructure scenarios.

5.1 Demand Scenarios

TSOs should develop a limited number of scenarios about the evolution (in the 10-year horizon) of energy and peak load. Such scenarios should consider:

- Historic (e.g., 10-year) and recent (e.g., 3-year) trends;
- Effect of weather conditions to electricity demand by end consumers (e.g., effect of temperature on hourly load using load-temperature models, in case the demand for electricity at national level changes significantly at high or low temperature levels);
- Expectations about the evolution of main parameters affecting electricity demand at a national level—such projections are provided by competent national authorities and usually include gross domestic product (GDP) and population growth;
- Demand (energy and peak load) projections provided by the DSOs—such projections are based on bottom-up analysis (usually on a regional and substation level), and include new household/commercial consumers expected to be connected as well as new industrial consumers (according to specific planned projects);
- Embedded generation from RES (e.g., solar, small wind parks, small biomass units, small run-of-river units, etc.), which are connected to the distribution network (thus affecting the residual load to be served by the transmission network);
- Policies concerning demand side management (energy efficiency, active participation of end consumers to load reduction, effect of the penetration of smart meters, etc.); and
- Other inputs, such as developments in central heating and microgenerators (for self-consumption), efficiency measures, and so on.

An assessment of the performance of previous forecasts and an explanation of relevant deviations should also be provided in the TYNDP.

5.2 Supply Scenarios

Supply scenarios should meet a set of desired properties:

- Be adequate, that is, assumptions for generation and imports/exports meeting the reliability criteria (deterministic or probabilistic) adopted by the TSO and other national authorities (NRA, competent ministries);
- Reflect national policies (e.g., decarbonization of the electricity system, exploitation of indigenous resources, SoS considerations, cross-border interconnections);
- Consistency with scenarios developed by other national agencies, for example, the gas TSO (especially with respect to economic growth assumptions, consumption of gas by the electricity sector, location of the main gas-fired units, etc.);
- Incorporate assessments of trading opportunities and availability of energy from cross-border interconnections;
- Deal at an appropriate level with uncertainties (e.g., energy production from intermittent RES, timing of commissioning, and planned or random outages of generating units);
- Be rational, in terms of viability of generation units (as measured by the load factor);
- Provide necessary flexibility (e.g., ramping capability) in cases of high penetration of intermittent RES; and
- Account for acceptable levels of dependence on or availability of imported fuels (e.g., natural gas).

5.3 System-wide Data Assumptions

This includes an assessment of:

- General macroeconomic (e.g., demographic, GDP, etc.) assumptions;
- Degree of dependence from electricity imports and imported fuels; and
- High-level technical assumptions used for elaborating the scenarios (desired level of reserve margin, unserved energy, loss of load probability) and system reliability (N-1 or N-2).

5.4 Global Infrastructure Scenarios

This includes an assessment of whether the assumed evolution of the generation and transmission system, expressed as a combination of the previously determined supply and demand scenarios and system-wide assumptions, meets the requirements set by national policies such as the target generation mix, cross-border interconnectivity, and reliability.

5.5 Checklist for Regulatory Appraisal

The NRAs must assess the network development and planning assumptions applied in each TYNDP (in Sections 5 and 6 of the recommended structure). Significant areas for systematic appraisal are:

1. Projections for electricity demand for the planning horizon with scenarios for electricity demand taking into account the main parameters affecting demand (GDP, sectoral characteristics of the economy in terms of energy demand, etc.);
2. Projections for peak load for the planning horizon, also taking into account the effects of temperature and demand-side management;
3. Supply scenarios characterized in terms of adequacy, flexibility, import dependence, and economic viability; and
4. Global infrastructure scenarios with sound justification for choices.

6. Categorization and Review of Projects

The overarching argument for categorizing investment projects into groups is that categorization facilitates the appraisal process. Each project category is considered to have different appraisal criteria and/or different weights attached to appraisal criteria. If projects are not categorized, that is, are all pooled and appraised together, it would be difficult to comparatively review and appraise them.

It is **recommended** that electricity transmission projects are classified into the following distinct categories, with regard to their objectives:

1. Resilience: security of supply, reliability, and safety;
2. Efficient Expansion: meeting forecast demand increase with minimum network losses;
3. Market Functioning: removal of internal congestion or efficient integration of regional markets;
4. Provision of Access: meeting generation or load connection needs; and
5. Strategically Planned: in accordance to national energy goals.

The following differentiated main reasoning is expected in the TYNDPs regarding each of the project categories.

6.1 Resilience

Resilience projects involve the provision of alternative transmission network routes to provide consumers with adequate and secure electricity supply at all times, as well as increasing the ability of the network to withstand extreme conditions (outage contingencies). These projects result in improvement of safety norms and reliability standards of electricity supply. The implementation of resilience projects will reduce the annual national energy not supplied (ENS) as well as the annual average interruption time (AIT) of electricity supply nationally.

6.2 Efficient Expansion

Construction, rehabilitation, or capacity increase projects for efficient expansion purposes, including the strengthening of connections between the TSO and DSOs, which are usually the majority in TYNDPs. Efficient expansion projects respond to a primary need for meeting a forecast demand increase, as well to facilitate the integration of renewable energy. The TSO must compare the costs for potential alternative expansion scenarios while also considering the monetary savings from the reduction of network losses in each.

Normal asset operation, routine maintenance, and end-of-life replacement are not included in rehabilitation projects within the TYNDPs. Rehabilitation projects included in the TYNDP refer to work specifically undertaken to restore the condition of assets in cases where routine maintenance by itself is unable to do so, or the early asset replacement is not the least cost option. They are designed to provide additional non-routine maintenance on assets that are in a condition of below acceptable standards, and may include a major overhaul of equipment or rebuilding or replacing parts or components of an asset to restore it to a required functional condition and extend its life.

For some equipment, replacement or uprating rather than rehabilitation may be the most appropriate and optimal long-term decision once all factors for efficient expansion are considered. Examples of such factors include safety and environmental considerations, age, increasing fault frequency, increasing cost and complexity of maintenance, lack of spares, obsolescence, and forecast conditions.

6.3 Market Functioning

Market functioning projects increase the ability of the transmission network to reduce congestion and provide an adequate grid transfer capability (GTC), so that electricity markets can trade power in an economically efficient manner. The GTC (measured usually in megawatts, MW, of transmission capacity) reflects the ability of the network to transport electricity across a boundary. A boundary may be fixed (e.g., a border between states or bidding areas) or vary from one time horizon or development scenario to another.

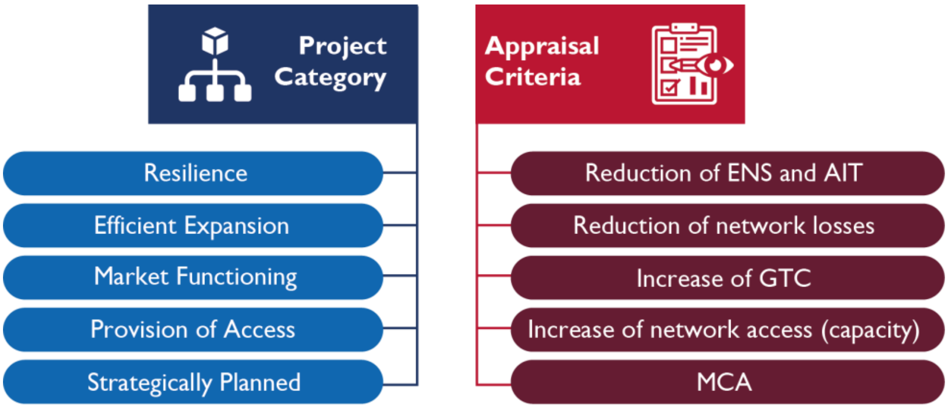
6.4 Provision of Access

Projects for the provision of access are responding to the need for the connection of new electricity generation or large load demand. The transmission network should always provide prospective users with adequate capacity to accommodate injections and consumption at the required specific locations, triggered by requests for interconnections (in particular for large-scale facilities).

6.5 Strategically Planned

These are projects whose implementation is favored by the national energy strategy, including SCADA, software for system surveillance, OPGW, and other cybersecurity investments in line with the national security of network and information systems strategy. Nevertheless, the capital expenditure for the construction of these projects must not be excessive. TSOs are generally less inclined to include many of such projects in their TYNDPs, as other alternatives may be less capital intensive or more cost beneficial on a purely economic basis. Appropriate incentives or gradual enforcement may therefore be required for the implementation of these projects. Also, other significant benefits from strategically planned projects may be considered in a multi-criteria analysis (MCA).

The project appraisal criteria for each of these **recommended** categories are summarized:



6.6 Project Presentation

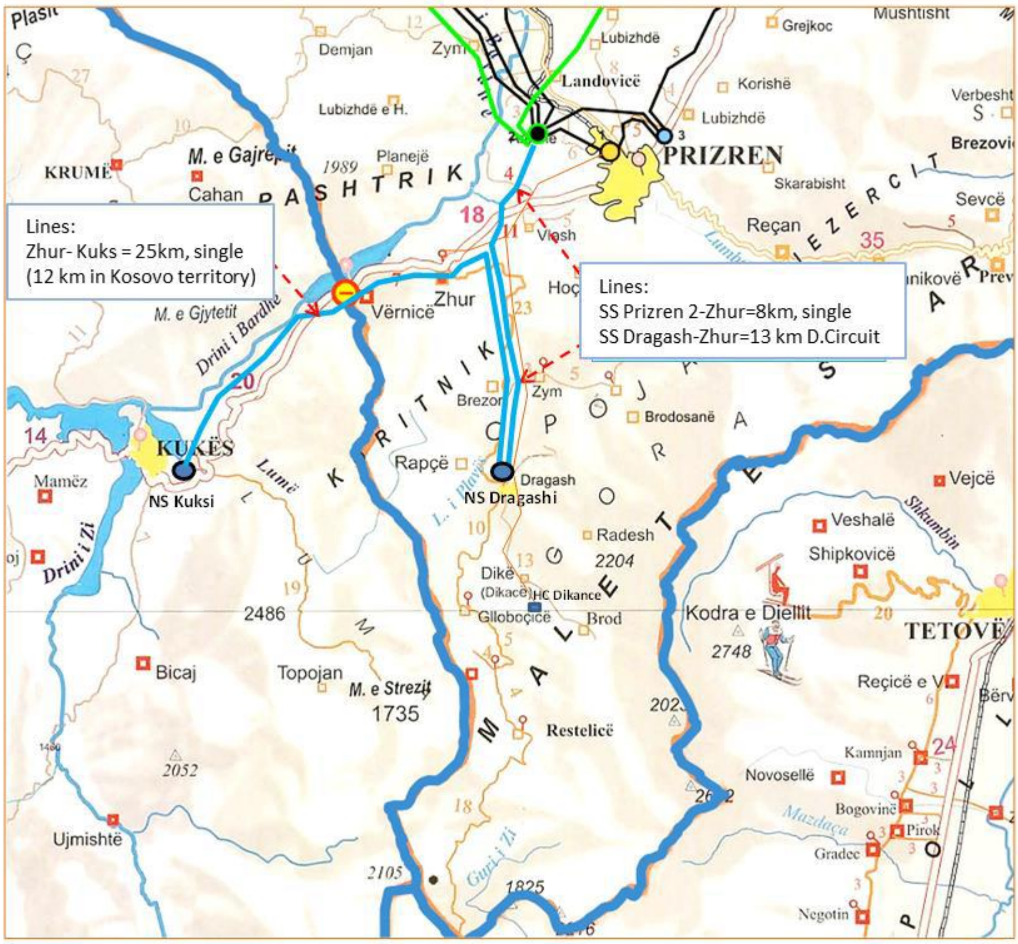
Each project must be reviewed and fully justified regarding its permitting, technical description, and costs. The economic prudence of each project must then be assessed, as elaborated in the next section. The following template is **recommended** for the uniform presentation of projects by the TSOs in the TYNDPs (indicative example provided from the 2017–2026 TYNDP of Kosovo). It is noted that a summary cost analysis must be presented for each project, along with quantified benefits, to allow for a CBA where necessary (as elaborated in the next section). Benefits that may be difficult to objectively monetize are also presented. These may be considered in an MCA (also elaborated in following sections and later illustrated in Annex 2 to this guide). The allocation of a uniform project code identifier is **recommended,** which must not be modified in subsequent TYNDPs. This is necessary for monitoring the TYNDP implementation as well as the process of annually updating TYNDPs.

Project Title:	*SS Dragash and 110-kilovolt (kV) line Kukës–Dragash–Prizren 2*
Project Code:	……
Purpose:	• *Qualitative and reliable supply of Dragash region* • *Reduction of power flows in SS Prizren 1* • *Optimization of systems operation in Kosovo and Albania*
Category:	*Resilience/efficient expansion/market functioning*
Cost Analysis: [in accordance to unit cost benchmarks]	• *SS Dragash, two 110-kV transformation fields, one 10 (20) kV and one 35 kV, two field lines, and one connection field of 110 kV: …… Euro* • *Single line, 8 kilometers (km) in length, Al/St 240 square millimeters (mm²) from SS Prizren 2 to Zhur (dual pillars): …… Euro* • *Dual line, 13 km in length, Al/St 2×240 mm² from Zhur to SS Dragash: …… Euro* • *Single line, 26 km in length, Al/St 240 mm² from Zhur to Kukës (9 km from Zhur to the border): …… Euro* *Total Investment Cost: …… Euro (disaggregated per construction year)* *Annual Maintenance Cost: …… Euro (0.1% of investment cost)* *Total 25-Year Life-Cycle (investment + maintenance) Cost: ……*
Benefits: [estimated from network simulation studies or past network performance]	*Considering the Dragash region as an area with a high potential for the development of mountain tourism and light industry, the construction of the new 110 kV substation will create optimal conditions to achieve security of energy supply. Benefits that Dragash consumers would have are:* • *Increased security of electricity supply through two 110-kV lines,* • *Quality and reliable supply,* • *Efficient supply reducing technical losses in the distribution network, and* • *Relief of power transformers in SS Prizren 1 to a load equivalent to the consumption in the region of Dragash.* *The project also includes the construction of the 110-kV interconnection line, which will connect, for the first time, the 110-kV transmission networks of Kosovo and Albania. Thus, in addition to the importance of the project to support the load of Dragash, this is considered a mutually beneficial project for Kosovo and Albania. Expected benefits for both countries are:* • *Optimization of power flow between the two systems of Kosovo and Albania,* • *Mutual exchange of electricity surpluses through radial operation of the connection line,* • *Increased security and reliability of supply for Kukës and its surroundings, as per the N-1 criterion, through reciprocal supply,* • *Increased quality and efficiency of supply of Kukës, and* • *Increased security of supply for the consumption of the Kalimashi tunnel AIT.*

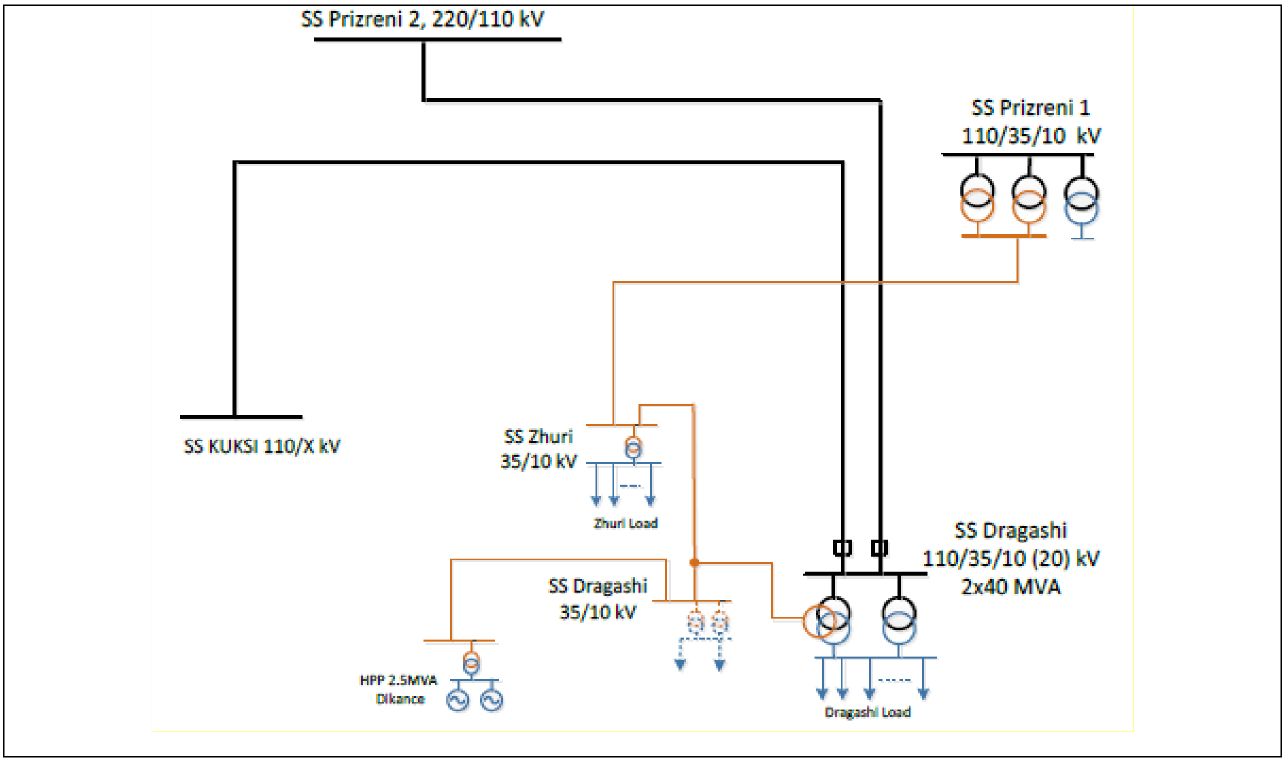
	Quantification: • *ENS: …… MW hours (MWh) annually (from past interruption recordings)* • *AIT: …… minutes annually (from past interruption recordings)* • *Losses Reduction: average …… MWh annually (from load flow studies)* • *Network Capacity Increase: …… MW (from equipment specifications)* • *Avoided Peaking Generation: …… MW annually (1% of peak demand)* • *GTC to/from Albania: …… / …… MW*
Permitting Status:	*No additional permits required*
Expected Commissioning Date:	*Fourth quarter of 2018*
Dependent Projects:	*None*
Complementary Projects:	*None*
Technical Description: [*within space limitations*]	*Consumption of electricity in the region of Dragash and Zhur is realized through the 35-kV and 10-kV distribution network extending in the southern part of the territory of Kosovo. The main supply line is the 35-kV line connected to SS Prizren 1 (110/35/10 kV) that supplies, in a serial connection, Zhur and Dragash consumption. A 35/10-kV substation is operating in Dragash, with two transformers of a total capacity of 8 + 4 = 12 megavolt-amperes (MVA). Security of power supply for the areas in question is not satisfactory. The main reasons are:* • *Consumption of Dragash and Zhur is supplied through a single 35-kV line, of the indirect ASCR 95 mm^2 section in a distance of 11 km to Zhur and an additional 11 km through a Cu 35 mm^2 conductor to Dragash. The narrow section and significant distance cause huge losses of active/reactive power, with a negative reflection on the quality of supply.* • *The voltage level of 35 kV, 10 kV, and 0.4 kV of the distribution network in the region of Dragash in high peak season is below allowed values provided in the Distribution Code.* • *Existing transformers 35/10 kV in the substation during winter consumption are overcharged and require load shedding to avoid total collapse of transformers. The same problem appears in the supply line of 35 kV with frequent overload operations, which often result in overload protection (disconnection of lines) and total supply cuts.* • *Disconnection of the single 35-kV line and planned load shedding to avoid total supply failure causes large amounts of undelivered electricity. Nondelivery of electricity harms the overall development of economic activities and lives of the people in the municipality.* • *The small hydro power plant Dikance is connected to Dragash SS 35/10 kV through the Cu 35 mm^2 35-kV line in a distance of 5 km. Any problem in the network/substation adversely affects the safety and reliability of operation of this hydropower plant. The significant*

	difference of voltage levels creates problems in the synchronization of Dikance with the 35-kV network. • *High tourism potential and the possibility to develop the light industry in the region of Dragash are negatively influenced as a result of the unreliable and poor quality of supply.* *Elimination of the aforementioned problems in the long term is achieved after the construction of a new substation 110/35/10 (20) kV, with a capacity of 2×40 MVA in Dragash and 110-kV transmission lines.*
Cybersecurity Considerations:	*No significant additional cybersecurity concerns*
Environmental Impact:	*No significant additional environmental burden expected*
Risks and Uncertainty:	*No significant perceived risks and uncertainty*

Topographical Map:



Single-line Diagram:



6.7 Permits

An important question that needs to be answered in the TYNDP is: Have all the legal, regulatory, and permitting obligations been met, or are they on schedule to be met before the planned project initiation?

For many projects, permits may be the most difficult obstacle for implementation. The Agency for the Cooperation of Energy Regulators (ACER) regularly monitors the progress of 109 large transmission projects of common interest (PCIs) throughout Europe, and reports (July 2018) a 3.8-year average duration for the permitting process. The expected duration of the permit granting for most of the PCIs is less than 5 years, typically between 2 and 4 years. But for 3 PCIs (3.7 percent of the total), the duration of the permit granting exceeds 10 years.

It is noted that ACER identifies[3] 13 stages in the project implementation cycle (after inclusion in the TYNDP), from which at least the first 6 stages (i.e., up to public consultation) would be necessary before the investment decision is taken:

1. Environmental study;
2. Spatial planning study;
3. Technical feasibility;
4. Socioeconomic feasibility;
5. Identification of alternative solutions/site identification;
6. Public consultation (when necessary);
7. Preparation of permitting files, contracts, and other documents;
8. Negotiation with landowners and land acquisition;
9. Detailed technical design;

[3] "Consolidated Report on the Progress of Electricity and Gas Projects of Common Interest for the Year 2016." ACER. July 2017.https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Consolidated%20Report%20on%20the%20progress%20of%20electricity%20and%20gas%20Projects%20of%20Common%20Interest%20for%20the%20year%202016.pdf

10. Tendering;
11. Preparatory works for construction;
12. Construction;
13. Commissioning.

The necessary permitting files (part of the seventh stage) are numerous and vary from country to country according to the detailed prevailing national legislation. Some of these are simpler and easier to obtain than others and thus may also be required before the investment decision is taken (i.e., moving the barrier from the end of the sixth stage to the mid-seventh stage). As an example, the first 4 from the following 10 groups of necessary permits identified in the 2015 Energy Investment Activity project for Bosnia and Herzegovina[4] could indeed be required, as necessary, before the investment decision is taken:

1. Concessions;
2. Water Acts;
3. Consent of Other Users of the Location;
4. Connection to the Distribution Grid;
5. Environmental Permit;
6. Urban Permit;
7. Approval of Project Documentation in Compliance with the Electricity Law;
8. Energy Permit;
9. Construction Permit; and
10. Use Permit.

6.8 Technical

An important question that needs to be answered in the TYNDP is: Are the technical descriptions and prefeasibility analysis of adequate detail and justification?

The elements of the template presented in tabular form earlier should be adequately completed to ensure technical justification. In particular:

- Purpose and category of the project;
- Identification and quantification of benefits;
- Identification of dependent and complementary projects; and
- Technical description, including demand forecast and description of work and their expected impact.

The environmental impact and overall project sustainability must also be presented in the TYNDP.

6.9 Cost

The costs and their underlying assumptions must be reviewed by the NRA. Unit cost benchmarks (materials and labor) are often applied to judge the reasonableness of cost estimates (e.g., for extending transmission lines). Preapproved typical unit costs may alternatively be applied by the NRA, thus guiding the cost assumptions applied by the TSOs.

The review of capital expenditures is greatly facilitated by comparisons with international and/or national benchmarks. Alternatives for key projects may be provided by the TSO to demonstrate that the option selected is the most appropriate from an economic and technical perspective. Appropriate

[4] "Permitting Regime and Obstacles to Investment in the Energy Infrastructure Projects in Bosnia and Herzegovina." USAID/Energy Investment Activity. December 2015. https://www.usaideia.ba/wp-content/uploads/2016/06/Report-on-Permitting-Regime-in-BiH-and-Obstacles-to-Investment-English-12-31-15-final.pdf

international benchmarks should concern projects of comparable characteristics, technologies, specifications, etc. National benchmarks concern land values, which can be estimated based on real market transactions for a comparable land in the vicinity, cost of local works, and so forth. Comparative benchmarks from past or ongoing projects, as well as between similar national electricity utilities, are also used, and benchmarks can be gathered from the submissions of regulated entities and national statistics. Benchmarking also concerns several indicators other than costs (e.g., CO_2 emissions).

It is noted that in Article 11 (paragraph 7) of EU Regulation 347/2013 on guidelines for trans-European energy infrastructure NRAs are required to establish and make publicly available a set of indicators and corresponding reference values for the comparison (benchmarking) of unit investment costs for comparable projects of the following electricity transmission infrastructure elements:

(a) high-voltage overhead transmission lines, if they have been designed for a voltage of 220 kV or more, and underground and submarine transmission cables, if they have been designed for a voltage of 150 kV or more;
(b) any physical equipment designed to allow transport of electricity on the high and extra-high voltage level, in view of connecting large amounts of electricity generation or storage located in one or several countries with large-scale electricity consumption in one or several other countries;
(c) electricity storage facilities used for storing electricity on a permanent or temporary basis in aboveground or underground infrastructure or geological sites, provided they are directly connected to high-voltage transmission lines designed for a voltage of 110 kV or more;
(d) any equipment or installation essential for the systems defined above to operate safely, securely, and efficiently, including protection, monitoring, and control systems at all voltage levels and substations; and
(e) any equipment or installation aiming at two-way digital communication, real-time or close to real-time, interactive and intelligent monitoring, and management of the network in view of efficiently integrating the behavior and actions of all users connected to it, in order to ensure an economically efficient, sustainable electricity system with low losses and high quality and security of supply and safety.

It is also noted that ACER has published a report on unit investment cost indicators and corresponding reference values for electricity infrastructure (Version 1.1, August 2015), considering planning, permitting, supervision, materials, and assembly costs. This includes:

1. Overhead lines (by voltage and number of circuits): for example, mean 407,521 Euro/km of 220-kV double circuit;
2. Underground cables (by voltage and number of circuits): for example, mean 2,224,630 Euro/km of 220-kV single circuit;
3. Subsea cables (alternating current and direct current);
4. Alternating current substations (by rating and voltage): for example, mean 38,725 Euro/MVA;
5. Transformers (by rating); and
6. High voltage direct current converter stations.

National transmission network materials and labor cost benchmarks can be developed from actual (post-implementation) data for at least the following important infrastructure elements:

- Replacement of network equipment or reinforcement of substations (per capacity);
- Replacement of transformers to increase their capacity (per size); and

- Construction of new transmission lines, substations, and so forth (per size, length, and capacity).

6.10 Checklist for Regulatory Appraisal

The NRA must verify the technical and costing information provided in each TYNDP (in Section 8 of the recommended structure). Significant areas for systematic appraisal are:

1. Balanced distribution of main projects in the five identified categories;
2. Identification of ENS and/or AIT improvement in each resilience project;
3. Identification of reduction of network losses in each efficient expansion project;
4. Identification of GTC increase in each market functioning project;
5. Identification of capacity increase in each project aimed at the provision of access;
6. Presentation of necessity and priority for strategically planned projects;
7. Status of all the legal, regulatory, and permitting obligations for project implementation;
8. Adequate technical description and project justification;
9. Identification of environmental impact and presentation of overall project sustainability;
10. Reasonable costing for overhead and cable line reinforcements;
11. Reasonable costing for the network reinforcement equipment;
12. Reasonable costing for the replacement of transformers; and
13. Reasonable costing for the construction of new transmission lines and substations.

7. CBA of Projects

Here are the basic principles and techniques for conducting an economic CBA of electricity transmission investment projects.

7.1 CBA

CBA refers to an analytic approach for evaluating the economic advantages or disadvantages of an investment project. This is done by assessing a project's wider costs and benefits to the economy and overall society.

CBA, as applied by TSOs in the context of TYNDPs, serves three objectives:

- To verify the necessity/attractiveness of a proposed investment project (from a societal perspective), for internal TSO planning purposes.
- To facilitate the NRA's review/approval of the TYNDP by demonstrating the necessity and attractiveness of planned investment projects. Adequate analysis and justification of TYNDP projects is important because the inclusion of projects in the annual TYNDP[5] and their review/approval by NRAs should be a key prerequisite for their actual implementation.[6]
- To support prioritization of projects over time and between competing projects serving identical or similar objectives.

However, because CBA is a time-consuming and costly exercise, it is usually reserved for larger projects (in terms of capital expenditure or technical characteristics) and/or projects of particular significance.

CBA is intended to capture and quantify all the economic benefits and costs of a project, including those pertaining to strategic objectives. Specific indicators such as ENS and RES integration can be used to estimate a project's impact in terms of strategic objectives (e.g., related to a country's security of supply and energy balance/mix).

It is **recommended** that clear instructions are provided to the TSO by the NRA, as part of secondary legislation (e.g., the national grid code), on two aspects:

1. **When to carry out CBA (i.e., at which stage of the project evaluation process) and for which projects?**

As discussed in Section 4, it is **recommended** that during the TYNDP development process, CBA is performed immediately after completion of network analysis. In network analysis, the projects that are necessary to eliminate any problems and violations with respect to the planning criteria are identified. Regarding the type of projects that should undergo CBA by the TSO, a flow diagram is presented in Section 4 that depicts the proposed steps when deciding whether to perform CBA for a specific project. Indicatively, in Greece the TSO is required by the NRA to carry out CBA for important projects that satisfy one of the following conditions:

[5] In interviews with Southeast Europe NRAs, it was observed that apart from TYNDPs, TSOs are often obliged to develop additional national network planning instruments, most often referred to as investment plans, which provide detailed technical and economic information on projects that are planned for the first one to three years of the TYNDP. However, for the purpose of this guide, and in line with ACER's practice (ACER Opinion No 08/2017 on Electricity Projects in the National TYNDPs and in the Union-wide TYNDP, 3 April 2017), all planning instruments (including investment plans) are considered to be part of the TYNDP.

[6] It is noted that the processes of TYNDP development, review/approval, and tariff-setting are distinct and are treated as such for the purpose of this guide.

- The project concerns interconnections with neighboring countries, or
- The project concerns connections of noninterconnected islands with the main transmission system.

The conditions set in other EU member states, regarding the requirement for performance of CBA are the following[7]:

- Spain: Projects of 400 kV or 220 kV;
- Italy: Projects with investment (capital) costs (CAPEX) > EUR 25 million; and
- UK: Projects with CAPEX > EUR 100 million.

EU Regulation 1303/2013 also sets high levels of thresholds for "compulsory" CBA for infrastructure projects seeking structural funding support: they have to be over €50 million. The respective threshold for projects seeking Instrument for Pre-Accession Assistance (IPA) funding is €10 million.

Because the investment cost thresholds for major projects that should undergo CBA vary significantly among countries, it is **recommended** that Southeast European NRAs set a threshold based on the size of projects in their respective TYNDPs. The threshold for major projects is such that approximately the largest 20 percent of the TYNDP projects undergo CBA. This threshold can be adjusted accordingly over time, as the network develops, and the size of investments increases.

Note: For the purpose of this guide, no distinction is drawn between the medium-term TYNDP and the short-term (e.g., 3-year) investment plan. All planning instruments (including investment plans) are part of the TYNDP. Nevertheless, a full CBA provides useful and reliable insights only when the economic projections, parameters, and assumptions accurately and realistically reflect expected developments within an acceptable range of uncertainty/error. Thus, CBA tends to be carried out only for projects that plan to be implemented within 3 to 5 years, which is a time horizon for which economic projections can be made with an acceptable degree of uncertainty. Whether the NRA requires CBA to be part of the TYNDP or another planning document, the key is that the economic projections, parameters, and assumptions used as input in the analysis are adequately described and justified, and that the analysis pertains to a time horizon over which accurate and realistic projections can be made within an acceptable range of uncertainty/error.

As presented in the flow diagram in Section 4 (Figure 3), CBA is occasionally complemented by financial analysis, aimed at assessing a project's financial/commercial sustainability when financing is sought for the project from donors, IFIs, or ministries. In particular, financial analysis is necessary to establish the financing gap of a project, that is, the necessary grant financing so as to induce implementation of the investment and/or mitigate the adverse impact of the investment on use-of-system tariffs. It is noted that such analysis falls outside the realm of responsibility of regulators with respect to TYNDP review and is usually the subject of review by other stakeholders that are directly involved in financing the project (donors, IFIs, ministries, etc.).

2. How should CBA be carried out?

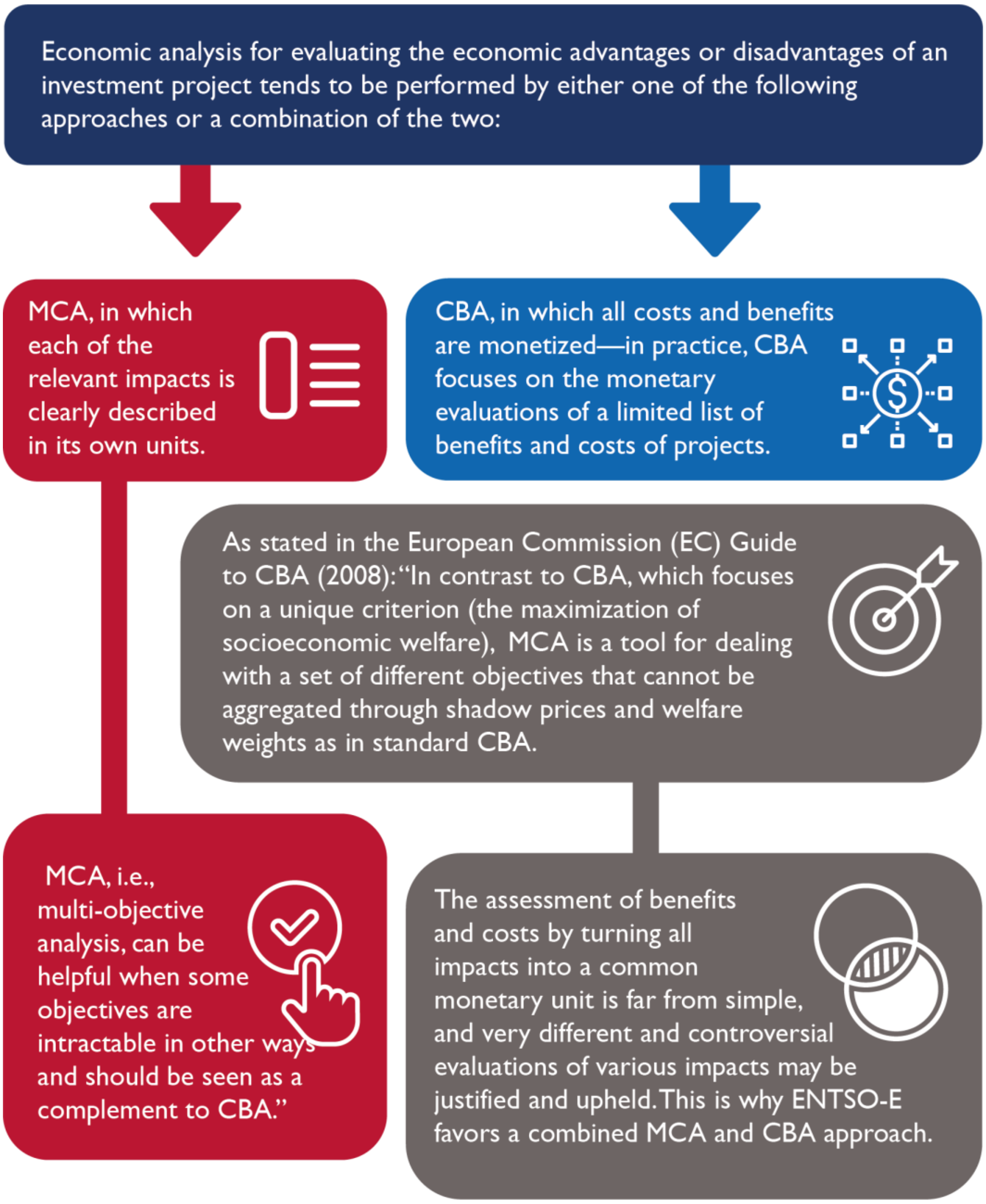
It is **recommended** that the TSOs develop a national economic CBA methodology and submit it to the NRA for review and approval. For this purpose, the ENTSO-E CBA methodology can serve as a guide, especially regarding the key principles and the framework that the national methodology should adhere to. However, the ENTSO-E CBA methodology does not provide definitive

[7] *ACER Report on CBA Methodologies for Electricity Transmission Infrastructure.* May 2016. https://www.acer.europa.eu/Events/ACER-workshop-on-scenarios-and-cost-benefit-analysis-methodology-for-assessing-cross-border-infrastructure-projects/Documents/Final%20Report%20-%20CBA%20and%20scenarios.pdf

directions/instructions on several aspects that are left open-ended for the NRA and the TSO to specify in further detail.

A distinction in the terms being used is provided in the following to facilitate the understanding of concepts and to ensure that common language is used.

MCA vs. CBA



The remainder of this section discusses the application and review of a CBA approach, in the sense described in the box above, complemented with consideration of some nonmonetary indicators.

7.2 Methodological Elements of CBA

Scenarios

The first element required in any CBA is the development of appropriate scenarios to represent potential future developments of the national energy system. They are characterized by a generation portfolio, demand forecast, and exchange patterns with the systems outside the national boundaries. The objective is to construct contrasting future developments that differ enough from each other to capture a realistic range of possible futures that result in different challenges for the grid. Scenarios thus serve as the basis for the further calculation of the grid development needs.

As described in detail in Section 5 of this guide, scenarios developed by the TSOs should have certain properties/characteristics. National strategic documents can serve as a guide for the development of these scenarios but should not constrain the TSO from developing its own justified assumptions (especially if the strategic documents are out-of-date).

Modeling studies

Market simulations: These are used to calculate the cost optimal dispatch of generation units, market exchanges between bidding areas, and corresponding marginal costs on an hourly basis, using a simplified model of the physical grid. Market studies are used to determine the benefits of providing additional transport capacity and enabling a more efficient usage of generation units available in different locations across bidding areas.

Network simulations: These are based on network models representing the transmission network in a high level of detail and are used to calculate the actual load flows that take place in the network under given generation and load conditions. Network studies enable the identification of bottlenecks in the grid corresponding to the bulk power flows resulting from the market exchanges and are particularly necessary input for market studies.

Both market and network studies provide different information and, as they complement one another, are often used in an iterative manner.

Redispatch simulations: These are a combination of market and network studies and are relevant for internal projects that do not show a significant impact on cross-border capacities (in terms of price zones). The redispatch simulations resolve overloads (taken from network simulations) by adjusting the initial dispatch (taken from market simulations) while maintaining the same power plant–specific constraints. The benefits of an internal project can be calculated like for cross-border projects by comparing two dispatching scenarios, with and without the project.

Clustering of investments

In situations where multiple investments depend on each other to perform a single function (i.e., one project cannot perform its intended function without the realization of another investment), these can be clustered and assessed as a single project.

Monetization of SoS benefits

National surveys are applied to estimate the value of ENS. CEER recommends for NRAs to perform nationwide cost estimation studies regarding electricity interruptions and voltage disturbances. CEER has issued a report that contains a recommended approach and guidelines for conducting such studies.[8] Typically, cost-estimation studies on electricity interruptions and voltage disturbances adopt a survey-based approach or a case-based approach. Survey-based approaches typically include the design of a questionnaire, which is sent out to a large representative sample. On the other hand, case-based approaches focus on a few single cases to identify the consequences of interruptions or voltage disturbances for these typical cases. Both approaches could be used for all consumer groups.

[8] *Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances.* CEER. 2010 https://www.ceer.eu/documents/104400/-/-/7dec3d52-934c-e1ea-e14b-6dfe066eec3e

Calculation of incremental benefits

The calculation of the benefits associated with a project is based upon a reference network model in line with the considered scenario. Two options are possible:

- Take One Out at a Time (TOOT) approach, which means calculating the difference for each indicator between the reference network model (project in) and the reference network model from which the project is excluded (project out).
- Put One In at a Time (PINT) approach, which means calculating the difference for each indicator between the reference network model onto which the project is added (project in) and the reference network model (project out).

Costs

For each project, costs must be reported, including items such as:

- Expected cost for materials and execution costs (e.g., towers, foundations, conductors, substations, protection and control systems, and engineering consultancy);
- Expected costs for temporary solutions that are necessary to realize a project (e.g., a temporary circuit has to be installed during the construction period);
- Expected environmental and consenting costs (e.g., costs for avoiding, mitigating, or compensating environmental costs under existing legal provisions, cost of planning procedures);
- Expected costs for devices that need to be replaced within the given period (consideration of project life cycle);
- Expected investments related to cybersecurity measures;
- Dismantling costs at the end of the equipment life cycle; and
- Maintenance and operation costs.

As described in Section 6.9 of this guide, unit cost benchmarks (materials and labor) can be applied by NRAs to assess the reasonableness of cost estimates by TSOs (e.g., for extending transmission lines). Pre-approved typical unit costs may alternatively be applied by the NRA, thus guiding the cost assumptions applied by the TSOs.

Cybersecurity

It is advisable that NRAs require TSOs to take into account the extent of cybersecurity risk in the various project-specific CBAs. To properly assess and account for the cybersecurity risk to which each project is exposed, the following needs to be understood and evaluated:

- The level of threats to which the project may be subjected (e.g., probability that a bad actor may propagate malicious software to compromise project functionality);
- The degree of project vulnerability against potential threats (e.g., the probability that the project functionality can be compromised); and
- The consequence (such as duration and extent of service interruption) when the functionality of a project is compromised.

7.3 Key Benefit Categories in CBA

Socioeconomic welfare (SEW)

SEW values transmission investments in terms of total generation cost savings, associated with the fact that a project that increases GTC between two bidding areas or alleviates congested internal boundaries inside an official bidding area may enable generators in the lower priced segment to supply power to the higher priced segment. In this case, the new transmission capacity reduces total fuel and other variable operating costs for power generation, which increases SEW. In general, two different approaches can be used for calculating the increased benefit from SEW in terms of savings in total generation costs:

- The *generation cost approach*, which compares the generation costs with and without the project;
- The *total surplus approach*, which compares the producer and consumer surpluses, as well as the congestion rent between them (if applicable), with and without the project.

The generation cost approach is more straightforward to calculate and less demanding in terms of data collection and modeling requirements. The economic benefit is calculated from the reduction in total generation costs associated with the GTC variation created by the project, via market or redispatch studies that optimize generation portfolios. There are three aspects to this approach:

- By reducing network bottlenecks that restrict the access of generation to consumers, a project can reduce total generation costs in the interconnected areas;
- A project can contribute to reduced costs by providing a direct system connection to new, relatively low cost, generation; and
- A project can also facilitate increased competition between generators, reducing the price of electricity to final consumers.

The benefit is monetized and calculated from the following relationship:

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

The total surplus approach is more complex to calculate because it requires the estimation of consumer and producer willingness to pay to determine consumer/producer surplus, as well as the estimation of demand and supply parameters (elasticities) through the collection of related data. The total surplus approach includes the following three elements:

- By reducing network bottlenecks, generation will be economically optimized. This is reflected in the sum of the producer surpluses in the interconnected areas.
- By reducing network bottlenecks that restrict the access of imports from low-price areas, the total consumption cost will be decreased. This is reflected in the sum of the consumer surpluses in the interconnected areas.
- Finally, reducing network bottlenecks will lead to a change in total congestion rent for the TSOs of the interconnected areas.

The benefit is monetized and is calculated from the following relationship:

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

In both approaches, 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. For each year of the horizon, these values should be discounted and then totaled to calculate a total benefit. The social discount rate (SDR) is used to calculate the present value of this benefit to the economy and society, which is a reflection of the society's relative valuation on today's welfare versus the future welfare driven by a project. There are large differences in SDRs, with developed nations typically applying a lower SDR (from three to seven percent) than developing nations (from eight to 15 percent), as developing/poorer countries place a higher value on funds today as opposed to funds in the future when compared with developed countries. EC has adopted a pan-European SDR recommendation of four percent.

RES integration

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

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

RES integration measures the impact of a project in terms of:

- The reduction of RES curtailment (from a reduction of congestion in the main system) that is calculated through market or network studies and measured in MWh;
- The additional amount of RES generation capacity that is connected to the main system, measured in MW.

The prospective amount of RES generation to interconnect to the system, in the time frame under examination, is estimated by the TSO as part of the supply scenarios that are developed for the purpose of the TYNDP (see Section 5 of this guide).

Variation in GHG and Air Pollutant emissions

Variation in GHG (e.g., CO_2) and air pollutant (e.g., SO_2, NOx) emissions measures the environmental impact of a project. Considering the specific emissions for each power plant and the annual production of each plant, the annual emissions can be calculated over the study horizon, measured in tons.

The variation in GHG emissions can be monetized on the basis of price projections derived from official sources such as the International Energy Agency that can be considered to capture the full long-term value of emissions. Regarding air pollutants, a key reference study estimating monetary values of energy infrastructure emissions in Europe is Extern-E.[9]

Variation in losses

The network efficiency benefit of a project is measured through the reduction of thermal losses in the grid.

At constant power flow levels, network development generally decreases losses, thus increasing 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 reduces losses.

The variation in losses is calculated through network studies and measured in MWh. It can be monetized using marginal cost estimates obtained through market studies.

SoS

SoS indicators measure the ability of a power system to provide an adequate supply of electricity to meet the demand at any moment in time. This requires that sufficient generation capacity is available, and that sufficient transmission capacity is in place so that all the consumer load at a given moment can be met.

If there is sufficient generation capacity in a given area to meet demand at all times, constructing additional transmission capacity will not lead to a reduction of lost load. Nevertheless, transmission capacity increases the adequacy margin by enabling the use of (surplus) generation capacity that is in a different location.

[9] http://www.externe.info/

SoS issues as well as the contribution of transmission capacity investment projects to the efficiency of spare generation capacity can be captured by two indicators:

- Expected ENS, measured in MWh: to capture the benefit of the project in case there is an actual loss of load detected under particular circumstances/conditions; and
- Additional adequacy margin, measured in MW: to capture the benefit of the project in terms of enabling the use of (surplus) generation capacity in different locations, if ENS equals zero.

Both indicators can be monetized:

- ENS by multiplying it with the value of lost load (VoLL) in €/MWh;
- Additional adequacy margin on the basis of the investment cost of peaking units (conservatively).

An example of applying CBA for an electricity transmission project is provided in Annex 1 in this guide.

7.4 Checklist for Regulatory Appraisal

The NRA must verify the application of CBA in each TYNDP (in Section 9 of the recommended structure). Particular issues that must be verified are:

1. Benefits shown by the TSOs for each project are relevant to the project category and are supported by the results of network and market studies;
2. The methodologies utilized by the TSO for monetizing each benefit are appropriate;
3. Underlying assumptions (including the SDR) pertaining to the type and monetization of benefits presented by the TSOs are appropriate; and
4. Cost estimates utilized by TSOs are reasonable and in line with available unit cost benchmarks.

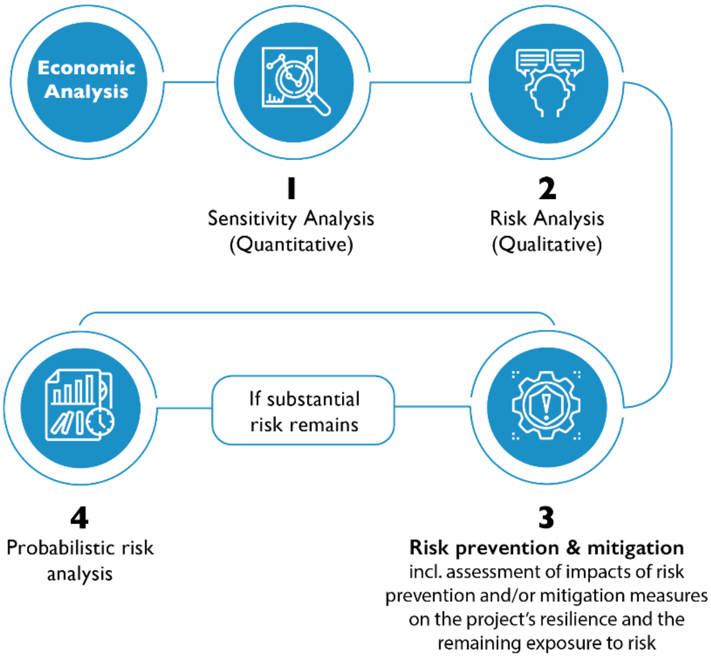
8. Risk Analysis

Risk analysis refers to the process of assessing the likelihood of potential adverse events and their impact on intended project outcomes. As discussed in Section 4, Risk Analysis is **recommended** for all projects that undergo a CBA. Risk analysis serves as a tool for:

- Characterizing the riskiness of assessed projects and deciding between competing projects with similar objectives and expected outcomes; and
- Taking appropriate steps to avoid or mitigate identified risks.

Risk analysis involves four main steps, as shown in Figure 4, which are discussed in turn in this section.

Figure 4. Risk Analysis Steps



8.1 Sensitivity Analysis (Quantitative)

Sensitivity analysis aims to assess a project's sensitivity and robustness to potential positive and negative changes in the input variables of the CBA. Sensitivity analysis in the context of TYNDPs includes the following components:

- Identification of the project's critical variables, that is, those variables that have the largest impact on the project's performance.
- Calculation of switching values for the project's critical variables, that is, the values that the analyzed variables would have to take for the economic net present value (ENPV) to switch from positive to negative (or inversely). The use of switching values in sensitivity analysis allows an assessment of the project's risk and the opportunity to undertake risk-preventing actions. For example, in case investment cost is deemed to be a critical variable for a project with positive ENPV, the related switching value indicates the level of the investment cost at which the project becomes economically not viable. If the switching value of a certain variable does not deviate significantly from its expected/estimated value, then the project is risky with respect to this variable. Thus, there is a need to further investigate the causes of this risk, the

probability of its occurrence, and identify possible corrective measures as described in the CBA/sensitivity analysis example provided in Annex I to this guide.

- Scenario analysis, which studies the impact of combinations of values taken by the critical variables. In particular, combinations of optimistic and pessimistic values of the critical variables are used to build different realistic scenarios. To define the optimistic and pessimistic scenarios, it is necessary to choose for each variable the extreme (lower and upper) values within a range defined as realistic. Again, some judgments on the project risks can be made on the basis of the results of the analysis. For example, if the ENPV remains positive, even in the pessimistic scenario, the project risk can be assessed as low.

8.2 Risk Analysis (Qualitative)

Risk analysis aims to assess the wider risks a project is exposed to, as well as any actions to remove/mitigate them and their impact. Risk analysis is qualitative and aims to capture and assess the risks associated with a project including, but not limited to, the factors analyzed as part of the sensitivity analysis. Importantly, risk analysis should also explicitly address risks associated with cybersecurity, particularly with regard to project-specific and network-wide information technology systems operations technology and control systems. Risk analysis includes:

1. A list of adverse events to which the project is exposed.
2. A risk matrix for each adverse event indicating:
    a. Possible causes of occurrence,
    b. The negative effects generated on the project,
    c. The probability of occurrence,
    d. The severity of impact (as assessed through sensitivity analysis, if applicable), and
    e. The resulting risk level.
3. Interpretation of the risk matrix including the assessment of acceptable risk levels.
4. Description of mitigation/prevention measures for main risks, indicating who is responsible for implementation of mitigation measures and their timing.

As demonstrated in Table 1, which is presented in the EC *Guide to CBA*,[10] the risk level in particular (item 2e above) is the combination of probability of occurrence (item 2c above) shown along the vertical axis and severity of the impact (item 2d above) shown along the horizontal axis.

Table 1. Risk Levels

		Severity				
		I	II	III	IV	V
Probability	A	Low	Low	Low	Low	Moderate
	B	Low	Low	Moderate	Moderate	High
	C	Low	Moderate	Moderate	High	High
	D	Low	Moderate	High	Very High	Very High
	E	Moderate	High	Very High	Very High	Very High

Source: Guide to Cost-Benefit Analysis of Investment Projects.

[10] *Guide to Cost-Benefit Analysis of Investment Projects*. EC, December 2014. http://ec.europa.eu/regional_policy/sources/docgener/studies/pdf/cba_guide.pdf

The EC *Guide to CBA* provides some guidance concerning the risk probability classifications, although in principle other classifications are possible:

- Probability A: Very unlikely (0–10 percent probability);
- Probability B: Unlikely (10–33 percent probability);
- Probability C: About as likely as not (33–66 percent probability);
- Probability D: Likely (66–90 percent probability); and
- Probability E: Very likely (90–100 percent probability).

Additionally, the EC *Guide to CBA* also provides the following guidance concerning classification of the severity of the impact (item 2d above) that specific risk can have on the social welfare generated by the project:

- Severity I: No impact;
- Severity II: Minor impact, minimally affecting the project's long-term effects;
- Severity III: Moderate impact, affecting the project's medium-term effects;
- Severity IV: Critical impact, causing a loss of the primary function(s) of the project; and
- Severity V: Catastrophic impact, leading to serious or total loss of the project functions.

Even after all possible prevention/mitigation measures are implemented, a residual risk level still remains. This residual risk should, in most cases, be low. However, residual risk could be high in cases of critical factors that are exogenous (i.e., outside the control of the implementer). In these cases, any mitigating actions may not have a strong influence on the risk. Table 2 demonstrates an example of a risk matrix.

Table 2. Sample Risk Matrix

Risk item	Possible causes	Negative effects on project	Probability (P)	Severity (S)	Risk level (= *P* * *S*)	Risk prevention / mitigation measures	Residual risk
Financial risks							
Investment cost (CAPEX) overrun	Inadequate CAPEX budgeting, feasibility analysis, etc.	Reduced ENPV/Economic Rate of Return (ERR)	C	III	Mode-rate	Project design must be revised	Low
…	…	…	…	…	…	…	…
Implementation risks							
Unforeseen technical problems during works	Inadequate site surveys and investigation	Delay in project commissioning	B	II	Low	…	Low
…	…	…	…	…	…	…	…
Environmental risks							
Negative impacts on protected areas	Inadequate environmental impact studies	Reduced ENPV/ERR	A	II	Low	…	Low
…	…	…	…	…	…	…	…

In principle, very high-level risks should be unacceptable and removed through appropriate risk mitigation and/or prevention measures to reduce the project risk prevailing in the various areas of the defined risk matrix.

8.3 Risk Mitigation and Prevention

Risk mitigation refers to actions aimed at systematic reduction of exposure to a risk (i.e., targets impact severity), while risk prevention aims to systematically reduce the likelihood of risk occurrence (i.e., targets the risk probability).

Key considerations when designing and implementing risk mitigation and prevention measures are the following:

- The intensity of the measure should be commensurate to the level of risk. In other words, for risks with a high level of impact and probability, a stronger response and a higher level of commitment to managing them should be implemented, while for low level risks, close monitoring could be sufficient;
- It is necessary to define who is responsible for the execution of each measure and in what stage of the project cycle (planning, tendering, implementation, operation);
- After the implementation of the measures, their impacts on the project's resilience and the residual risk for each adverse event needs to be assessed. If risk exposure is assessed to be acceptable, the proposed qualitative risk strategy can be adopted. If a substantial risk remains, it is required to move to a probabilistic quantitative analysis to further investigate the project risks; and
- A key but costly measure to mitigate the financial (but not the economic) impact of specific risks, which must be considered by the TSO, involves the transfer of risks to risk management institutions such as insurance companies.

Generally, a neutral attitude toward risks is **recommended,** in which the riskiness of projects (as long as this is within acceptable limits) is not a criterion for their selection. However, project riskiness could be a criterion for deciding between competing projects with similar objectives and expected outcomes. Several measures/policies can be adopted by the NRA to mitigate risks, in particular regulatory risks that can be influenced by the NRA's regulatory framework, so as to increase the attractiveness of specific investment projects on a case-by-case basis. These relate primarily to the following three categories:

- Cross-border coordination issues related to differences between national regulatory frameworks, which can lead to uncertainty in the way projects are treated from a regulatory perspective;
- Future adverse regulatory decisions including direct intervention in cost recovery mechanisms (regulated asset base, weighted average cost of capital, etc.); and
- Financing issues such as failure in ensuring adequate investment capital and difficulties of project promoters in maintaining liquidity.

The two most effective and commonly used types of regulatory measures are:

- Stability provisions, and
- Measures to mitigate liquidity risk.

Stability provisions are aimed at providing regulated companies with some guarantee of regulatory stability. Such measures can include:

- Using fixed regulatory terms, where the NRA guarantees not to adjust certain key factors during a specific period of time, or even a total ban on retroactive decisions such as lowering the allowed return on investment;
- NRA consulting with regulated companies to get their views on any proposed regulatory changes and on how the adverse impact of proposed changes can be mitigated; and
- Gradual implementation of regulatory changes to facilitate the transition of regulated companies.

Measures to mitigate the liquidity risk include the following:

- Early recognition of costs, that is, inclusion of asset values into the regulated asset base and/or of their related costs into the operational expenditure before the new asset is commissioned, and when the expenditure is incurred;
- Commitment by the NRA that once an investment is part of the national development plan, the CAPEX will be approved and fully covered by national tariffs, so as to eliminate the risk of stranded assets from the perspective of the TSO (users will still have to pay for the asset through the tariffs); and
- Using a more favorable depreciation regime.

8.4 Probabilistic Risk Analysis

Probabilistic risk analysis is required where the residual risk exposure is still significant, in order to have comprehensive information about the risk profile of a project. Key steps are:

1. Assign a probability distribution to each of the critical variables of the sensitivity analysis, defined in a precise range around the best estimate. The probability distribution for each variable may be derived from experimental data, distributions found in the literature for similar cases, consultation with experts, and so forth;
2. Use of Monte Carlo simulation through appropriate software to produce repeated random extraction of a set of values for the critical variables;
3. Calculate the performance indices (ENPV/ERR) resulting from each set of extracted values and obtain the probability distribution of the ERR/ENPV; and
4. Decide on the necessity of additional preventive and mitigation measures.

In the event that the ENPV (or other indicator) as calculated in the CBA, on the basis of the main assumptions with respect to critical variables, deviates significantly from the mean (or expected value) derived from probabilistic analysis, it is **recommended** to base the assessment/acceptance on a criterion involving the latter. For example, if a project has an ERR of 10 percent but also the probability risk analysis informs us that the ERR has a value between 4 and 10 percent with a probability of 70 percent, and a value between 10 and 13 percent with a probability of 30 percent, then the mean (or expected value) of ERR for that project is only 8.35 percent, that is, average (4,10) * 0.7 + average (10,13) * 0.3.

8.5 Checklist for Regulatory Appraisal

The NRA must appraise the risk and sensitivity analysis presented in the TYNDPs (also in Section 9 of the recommended structure) to assess the robustness of the project's results to potential variations in critical parameters. Particular issues to consider are:

1. Are tested variables deterministically independent (i.e., not characterized by an exact relationship) and as disaggregated as possible?
2. Have all independent variables of the project been analyzed and are critical variables and switching values clearly identified?
3. Is the criterion for identification of critical variables appropriate?
4. Is the list of risks/adverse events exhaustive to the fullest extent possible, including also risks that are out of the control of the project promoter or other stakeholders (i.e., change of legislation)?
5. Are risk causes and risk impacts/effects adequately identified and discussed in sufficient detail?
6. Does the severity of impact analysis adequately capture the extent of identified impacts/effects?
7. Have prevention/mitigation measures been identified for all risks?
8. Are the identified measures appropriate in terms of effectiveness and timing and is their intensity commensurate to the level of risk?
9. Are there any regulatory risk mitigation measures that the NRA can undertake?
10. Has a probabilistic risk analysis been carried out, in cases where after the identification of all possible prevention/mitigation measures considerable residual risk remains?

9. Regional Projects

Electricity transmission projects may affect multiple interconnected countries because of the physical laws governing electricity flows. Electricity transmission projects that have a regional effect (affecting more than one country) can either be cross-border interconnections or even projects that geographically reside within a single country, but have a wider impact.

9.1 Costs and Benefits of Regional Projects

Large-scale regional transmission projects should be implemented subject to the positive results of a CBA at the regional level. Such analyses are usually very complex exercises because they have to identify and calculate (monetize) benefits stemming from a transmission project for a horizon that exceeds 25 years (the minimum technical or economic life of a large-scale transmission project).

The CBA would calculate the benefits accruing to each country affected by the project. The whole process may work as follows:

- In general, a pre-CBA (i.e., a first assessment of potential costs and benefits) for a regional transmission project is initiated by the party (or parties) that feels they will reap significant benefits (cost savings, fostering of competition, reliability increase, SoS, etc.).
- Depending on the national legislative context, such a party might be the competent ministry, the TSO, or even the NRA.
- As a next stage, countries involved territorially (i.e., countries crossed by the regional transmission project) would join forces to conduct a more detailed CBA, in which most—if not all—of the costs and benefits would be identified and estimated (quantitatively or qualitatively). Depending on the case, even non-territorially involved countries might initiate or participate in the CBA, for example, when such countries are significantly affected by the project under study. Again, the abovementioned actors (ministry, TSO, NRA) would be involved in conducting the study, potentially assisted by an external consultant.
- A third party (private investor) may conduct the CBA in cases in which the legislative framework allows private investors to develop transmission projects.

Another challenging issue regarding regional projects is the allocation of the project's cost. Cost may be allocated according to various methods. The traditional method of cost allocation is that each country builds, operates, and finances the infrastructure on its own territory. Under this approach, a first assessment should therefore be to check if the project is economically beneficial (i.e., with net positive CBA) for the countries hosting it. If that is not the case, but significant overall benefits have been established by the project, part of the costs could be allocated across borders to make the project economically beneficial (i.e., with net positive CBA) for each and every country involved. To this end, the following cost allocation methods can be applied:

1. *Proportional approach*: For each project, each country contributes their proportional share of the benefits. From an economic perspective, this leads to optimal decision making. In this way, cost allocation leads to an outcome that appeals to intuition, since the ratio between benefits and contribution is equal for each affected country.

2. *Minimum contribution approach*: Affected countries, in which the investment does not take place, pay the difference between costs and benefits in the investing countries. By paying only the difference between costs and benefits, one would essentially compensate the losers without punishing the countries benefiting from the project.

ACER, in its Recommendation No 05/2015[11] on cross-border cost allocation (CBCA), provides the main principles that NRAs should follow when assessing cross-border projects for deciding on the allocation of costs and their inclusion into the tariffs. This recommendation is based on the minimum contribution approach, providing a regulatory tool addressing the uneven distribution of costs and benefits from transmission projects with cross-border effects. Overall, a negative net benefit in one of the hosting countries is a significant barrier in the implementation of regional projects.

It is also noted that, especially in the case of regional projects (e.g., interconnections between two national systems), appropriate cybersecurity considerations have to be taken into account because of the need for multiple energy control centers to coordinate and the increased risk from large system interconnectivity (leading to the necessity to move toward common standards).

9.2 Checklist for Regulatory Appraisal

The NRA must verify the information provided for regional projects in each TYNDP (within Section 8 of the recommended structure). Significant questions for consideration are:

1. Are there projects which impact neighboring countries, and if so, has the impact been assessed/monetized (e.g., through CBA)?
2. Has allocation of the costs of regional projects in the impacted countries taken place?
3. If cost allocation is present, is the cost allocation method described?
4. Is the method used for allocating the costs sound from a political/economic point of view (e.g., territorial, proportional, minimum compensation)?

[11] "ACER Recommendation No. 5/2015 on Good Practices for the Treatment of the Investment Requests, including Cross Border Cost Allocation Requests, for Electricity and Gas Projects of Common Interest." ACER. https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2005-2015.pdf

10. Project Prioritization and Impact

Following the review, economic CBA, and risk and sensitivity analysis of electricity transmission projects included in the TYNDPs, the overall prioritization of projects and other infrastructure investment elements per category (resilience, efficient expansion, market functioning, provision of access, strategically planned) must be appraised by the NRA, along with the overall impacts from each TYNDP.

10.1 Project Prioritization

The main reasons why the TSOs must prioritize transmission projects are budgetary as well as resource restrictions, which necessitate ranking according to importance to further define the time sequence for project implementation (short-term, medium-term). Even if the full required budget is available, and even if the TSO subcontracts or outsources significant elements of its investment plan, TSO staff must specify in detail, supervise, and proactively monitor the implementation of the work. Many very ambitious TSO plans have in practice been delayed because of TSO resource limits.

It is important for prioritization to be carried out separately for each project category, reflecting the differences in the nature of the projects. Indicative prioritization methods include:

1. *Investment drivers*: Give priority to projects according to the degree in which they meet the key investment drivers of the TSO;
2. *Gradual elimination*: Listing the attributes of each project in a large matrix and methodically eliminating the comparatively inferior projects;
3. *Stakeholder weighting*: Decision of (average) weight for each attribute (i.e., cost or benefit element) in a representative multi-stakeholder meeting, for example, as part of an integrated resource planning (IRP) process; and
4. *MCA*: Considering all project independent and non-correlated attributes in a consistent manner (e.g., via an analytical hierarchy process [AHP] as described in Annex 2 to this guide).

10.2 Project Implementation Time Plan

The selection and prioritization of projects and other infrastructure investment elements for the first 3 years and the next 7 indicative years of the TYNDP must be particularly scrutinized. Factors to take into consideration in this prioritization are:

- Overall reasoning provided per investment element in the TYNDP (in Section 4 of the recommended structure);
- Project presentation (in Section 6 of the recommended structure); and
- CBA undertaken for the main electricity transmission projects (in Section 7 of the recommended structure).

It is considered that the decision to invest has been taken for projects included in the first 3 years of the TYNDP. This investment decision may, however, be retracted following each annual TYNDP monitoring process (as elaborated in Section 13 of this guide) if important permitting issues arise during its detailed technical design before initiating implementation, or if the detailed cost estimates are much higher than initially anticipated (e.g., exceeding 30 percent). The investment decision may also be retracted on a case-by-case basis as necessary if fundamental technical, integrated grid or even national economic parameters on which it was based have changed. This can happen even after initiating the project's construction, according to the severity of the change and size/significance of the project, if this has not yet already progressed significantly (e.g., not exceeding 30 percent).

The full prioritization of all candidate projects (to select the ones to be included in the TYNDP) is typically not included in the published versions of electricity TYNDPs. It is carried out internally by the TSOs during the initial appraisal of candidate projects, to determine the preferred infrastructure to be included in the TYNDP. An important factor for the NRA to consider favorably and promote is the inclusion of specific cybersecurity projects (including evolving and upgrading cybersecurity software in the network's SCADA system) or add-on cybersecurity elements integrated within other projects in the TYNDP, as these are becoming increasingly necessary because of the increase in automatically controlled electricity networks.

Furthermore, contingency plans must be identified should key assumptions cease to hold or the selection criteria and focus change.

10.3 Impact on Transmission Quality

Following project prioritization and setting the TYNDP time plan, it is **recommended** that the mixture of projects/investments and their overall impact is examined by the NRA, for example, through the following quality indicators:

ENS

$$ENS = \sum_{i=1}^{K} P_i \cdot D_i$$

where P_i is the capacity disconnected (in MW) during interruption i, which lasts a period D_i (in hours).

AIT

ENS is divided by the average power supplied by the transmission network (in MW).

System Minutes

The load (MW) lost in a disturbance is multiplied by the duration of disconnection (in minutes) and divided by the peak system demand (in MW).

10.4 Impact on Overall Tariffs

It is **recommended** to also include in the TYNDP an analysis of the impact on its required revenue from implementing the projects expected to be commissioned in the first 3 years. If this is considered very high, requiring a large increase of consumer tariffs, the implementation of some of the lower priority projects may need to be shifted further in time. In selecting the projects potentially necessary to shift in time, the impact on transmission quality (ENS, AIT, system minutes, etc.) should be a primary consideration.

The required revenue must be calculated in line with the national tariff methodology. It should be calculated for each of the first 3 years, under the current state of the transmission network (i.e., without implementing any of the TYNDP investments) and in a scenario where all TYNDP projects are implemented.

It is noted that if the TYNDP includes competing projects that cannot coexist, that is, alternative projects serving the same or similar objectives from which only one will be implemented, the TSO in analyzing the impact on required revenue must take into account only the highest priority project. This is necessary to result in a realistic representation for the plausible system development.

10.5 Checklist for Regulatory Appraisal

The NRA must appraise the mix and prioritization of projects and other infrastructure investment elements included in each TYNDP (in Section 8 of the recommended structure, based on the TSO characteristics and network development drivers identified in Sections 3 and 7, respectively). Particular issues which must be assessed are:

1. Justification of project prioritization;
2. Identification of contingency variations in implementation time plan;
3. Consistency of strategically planned investments with TSO vision and investment drivers;
4. Reduction of annual ENS and AIT;
5. Reduction of system minutes; and
6. Appropriateness of methodology to compute the required revenue.

11. Stakeholder and Public Consultation

The involvement of stakeholders, through questionnaires or public consultations, is a key element of the appraisal process for TYNDPs. It ensures that this process is open, transparent, participatory, systematic, clear, and credible. Consensus-driven open dialogue procedures must be established at an early stage between the NRA, the TSO, other stakeholders, and the general public (including the ministry responsible for energy as well as local administrations, other government agencies and policy makers, business chambers, consumer associations, academic and research institutions, etc.). Stakeholder and public consultations must be widely publicized in advance.

Stakeholder and public consultations additionally serve two other very important purposes that influence significantly the realization of TYNDPs:

1. They make local communities familiar with the network projects under development, soften their reactions, and make network projects more acceptable to them; and
2. They help the TSO to understand and have a closer look at environmental aspects of the designed projects and the effects these bring about to the environment.

11.1 Stakeholder Consultation

Stakeholder consultation is a particularly strong feature of the IRP approach. In contrast to traditional planning that is typically top-down with stakeholder consultation occurring only as a last step (when the plans are virtually complete), the IRP makes the planning process more open to relevant governmental agencies, consumer groups, and others, thus considering the needs and ideas of all parties with a stake in the future of the electricity transmission network.

The open and transparent stakeholder consultation of TYNDPs is a key responsibility of NRAs in Directive 2009/72/EC concerning common rules for the internal market in electricity. The key principles for effective stakeholder consultations are:

- Consistent and flexible approach;
- Proportional scoping approach;
- Identify and understand stakeholders;
- Start consultation early;
- Provide adequate information to stakeholders;
- Targeted mix of consultation methods;
- Open and transparent process;
- Provide feedback, monitor, and evaluate; and
- Proactive and meaningful engagement.

A detailed recording of all issues or questions raised in the stakeholder consultation process must be documented and publicized, along with the specific responses provided by the NRA or the TSO. Following a public consultation process (physical meeting or web-based consultation) on the draft TYNDP, the TSO must take into consideration the comments/questions submitted and, if they are reasonable and justified, adjust the TYNDP accordingly. The TSO and NRA must explain why a participant's comment or remark was accepted or rejected.

It is **recommended** that stakeholders are individually invited to participate in the open public consultation process, also provided with appropriate versions (or presentations) of the TYNDP and any other complementary documentation. It is **recommended** that stakeholders invited to the public consultation process include at least the:

- Ministry responsible for energy;
- Existing generation utilities and other prospective generation investors;
- Transmission and distribution utilities operating in the TSO's area;
- Regional governments;
- Consumer associations and non-governmental organizations (NGOs);
- Environmental associations and NGOs;
- Engineering associations;
- Renewable energy associations;
- Standardization association;
- Industrial and commercial chambers; and
- Energy policy, planning, and research experts.

11.2 Improvement of Stakeholder and Public Consultation

The implementation of transparent and effective stakeholder and public consultation processes for TYNDPs is a key responsibility of NRAs. They are also a very important tool for TSOs in developing their TYNDPs, and therefore several TSOs opt to proactively undertake rigorous stakeholder and public consultations during the TYNDP development process. This provides stakeholders with the information they need to participate in a meaningful way and helps the TSO understand their concerns. It also provides an opportunity for the TSO to explain to those affected how and when they can have input to the new transmission development projects.

Ireland's TSO EiRGrid made the commitment in 2014 to carry out a detailed review of its consultation process to enhance future public engagement regarding TYNDP projects, involving a review of public feedback and international best practices in public consultation, as well as two independent external expert reviews of its process. EiRGrid subsequently compiled and publicized a set of commitments arising from recommendations and lessons learned from this review:

Theme 1: Develop a Participative Approach

1. Clear Communication: Ensure that information is presented in a straightforward way;
2. Process for Consultation in Project Development: Improve the effectiveness of the consultation process to clearly define consultation opportunities, to explain how feedback can be provided, and to efficiently assess feedback received;
3. Consultation Toolkit: Clearly explain the available methods of consultation and involve stakeholders in developing these methods;
4. Improved Community Relationships: Locate staff in the regions to facilitate enhanced dialogue with local communities and interest groups and to develop sustained long-term relationships in local areas;
5. Demonstrate Consideration of Social Impact: Increase the transparency of the consultation and decision-making process;

Theme 2: Change Culture and Processes

6. Consultation Handbook: Create a consultation handbook that sets out the purpose and principles of the consultation process, to ensure that high standards are met;
7. Consistency of Information: Consistently review a project to ensure the original network need remains, the proposed solution is appropriate, and any changes are communicated in a transparent and consistent manner;
8. Complaints Process: Immediately put in place a system to manage and investigate complaints or feedback, which will provide the opportunity to investigate and resolve a complaint;

Theme 3: Encourage Leadership and Advocacy

9. Support of Policy Makers: Encourage state agencies and other bodies to participate in a broader debate on why new or enhanced electricity infrastructure is required;
10. Input from Representative Groups into the TSO's Approach to Grid Development: Establish a structured approach to work more cooperatively with national representative groups and with the associations who are acknowledged as key influencers;
11. Regional Discussion Forums: Create forums to allow for meaningful dialogue on different technical and environmental matters when developing the grid; and
12. Independent Electric and Magnetic Fields (EMF) Monitoring and Compliance: Comply with any recommendations from the separate review of the latest research and developments concerning EMF, and also investigate the role an independent body could play in the area of monitoring EMF levels for both compliance and reassurance.

11.3 Checklist for Regulatory Appraisal

NRAs must strive to implement an efficient and effective stakeholder and public consultation process regarding TYNDPs. The following particular stakeholder and public consultation steps are **recommended,** composing a two-way flow of information and opinion exchange over a single public/stakeholder consultation cycle:

Before the public consultation process

1. The NRA publicly announces in its website the date and venue for a public consultation process (physical meeting or web-based consultation, to take place within 3 weeks or more from the announcement), soon after receiving the TYNDP from the TSO;
2. The NRA at the same time requests the TSO to provide, within a week, an appropriate version of their TYNDP for stakeholder dissemination;
3. The NRA without delay sends by email and fax individual invitations to key stakeholders and experts for the public consultation process, including the provided version of the TYNDP;
4. The NRA assembles all comments/questions, which may have been received by email or fax 2 days before the scheduled date for the public consultation hearing meeting (in case this is the selected consultation mode), to make these available to all participants on the day of the meeting;
5. The NRA sends a reminder by email to the key stakeholders and experts 2 days before the scheduled date for the public consultation hearing meeting;

During the public consultation process

6. The TSO initiates the public consultations by presenting the TYNDP, including the implementation performance of its previously approved TYNDP in the past years;
7. The NRA provides its initial (high level) comments on the presentation of the TYNDP;
8. The NRA refers to the comments/questions already received and provides (high level) responses of the NRA and/or TSO on important issues;
9. The stakeholders and other participants present their remaining comments/questions on the TYNDP;
10. The TSO or NRA provide (high level) responses to important issues raised in the new comments/questions;
11. The NRA invites the participants to submit their new comments/questions (expressed during the public consultation hearing meeting) by email or fax within 3 days;

After the public consultation process

12. The NRA publicly provides in its website the full list of comments/questions received (before, during, and after the public consultation process) within 5 days from its conclusion;
13. The NRA publicly provides in its website the responses provided (by itself or the TSO) for each of the documented consultation comments/questions, at the same time as its formal response to the TSO;
14. The NRA publicly announces in its website the formal approval of the TYNDP (following potential revisions by the TSO); and
15. The TSO uploads an appropriate version of the approved TYNDP on its website, within 2 weeks from the formal approval.

12. Presentation to Stakeholders and the Public

Further to the consultation of key energy sector stakeholders, it is equally important to summarize, present, and disseminate information on the approved electricity transmission investments to the general public. In the interests of transparency and information dissemination, TSOs must publicize their annual reports and TYNDPs (potentially less detailed versions) on their websites. The NRAs must also publicize their annual reports and information on the approval process for investment plans.

The purpose of dissemination of the whole TYNDP through availability on the internet is to help users and decision makers to analyze, compare, and understand the TYNDP through viewing past results, methods, drivers, legislation, constraints, and so forth. Furthermore, dissemination of information about specific projects helps to increase awareness of local/regional actors and the general public to help toward acceptability of the planned transmission projects.

12.1 Dissemination Messages and Channels

A key message and the dissemination audience must first be determined. The reasons for disseminating TYNDP project information include compensating for situations in which a thorough public consultation process is not undertaken or informing authorities and the general public about the local and regional impacts and prospects from the transmission expansion projects.

It is clear that not all projects that appear in the TYNDP need to be presented to policy makers, other stakeholders, and the general public. Routine transmission expansion projects, such as upgrades of existing transmission lines or substations, need not be further presented to stakeholders. On the other hand, projects of large scale or high cost and/or importance (e.g., in terms of system reliability, environmental impact, security of supply, internal congestion, or loop flows in neighboring countries) may be necessary to be further presented and disseminated to policy makers and the general public.

Dissemination channels and tools can include meetings, press releases, frequently answered questions, brochures, fact sheets, web pages, speeches, direct mail, phone calls, reports, social media, advertisements, newsletters, posters, videos, transcripts, press conferences, forums, seminars, annual reports, or public information centers.

12.2 Information for Dissemination

In general, the following information is **recommended** to be widely disseminated in a summary form where appropriate:

- Name of project;
- Ownership;
- Components and voltage level;
- Location/geographical region;
- Drivers/needs from which the project is necessary (e.g., request for transmission capacity by current or future users);
- Expected results (e.g., removal of congestion, increase of transmission capacity in an area, increase of reliability);
- Environmental aspects and issues (e.g., length of transmission lines in environmentally sensitive areas or near inhabited areas, dialogue and any concerns expressed by local stakeholders);
- Cost (total and/or per major component);
- Benefits (monetized or not);

- Net present value;
- Financing information;
- Competing projects;
- Risks (e.g., financing, licensing);
- Project status in terms of physical progress (feasibility study, licensing process, etc.);
- Project status in terms of financial cashflows incurred;
- Expected start and end date;
- Major comments and concerns expressed during the public consultation and the manner those were taken into account;
- Local economic impact (local operators, maintenance needs, etc.); and
- For interconnections with neighboring countries in particular: status of negotiations/agreements with neighboring stakeholders, CBCA, and project status in neighboring country (or countries).

An approximation with respect to the type of information that would be of most interest to disseminate to the three key stakeholder categories is **recommended:**

1. Decision makers (e.g., competent ministries in the areas of finance, energy, environment, external affairs, public works);
2. Energy sector stakeholders (generators, transmission-level consumers, suppliers, traders, etc.); and
3. Local/regional stakeholders (authorities and the general public).

12.3 Checklist for Regulatory Appraisal

The following steps are **recommended** for presenting the approved electricity transmission investments to decision makers, stakeholders, and the general public:

1. Summarize information on the approved electricity transmission investments to be presented;
2. Determine types of dissemination audience (decision makers, energy sector stakeholders, local/regional stakeholders, and the general public);
3. Determine key presentation message for each audience type;
4. Determine dissemination channels and tools; and
5. Effectively present and disseminate information.

INFORMATION	DECISION MAKERS	ENERGY STAKEHOLDERS	LOCAL STAKEHOLDERS
PROJECT IDENTITY			
1. Name/title			
2. Ownership			
3. Components and voltage level			
4. Location/geographical region			
5. Drivers/needs from which the project is necessary			
6. Expected results			
ENVIRONMENTAL IMPACT			
7. Environmental aspects and issues			
8. Detailed siting information			
ECONOMIC/FINANCIAL INFORMATION			
9. Cost			
10. Benefits			
11. Net present value			
12. Financing information			
13. Competing projects			
14. Risks			
15. Local economic impact			
PROJECT'S PROGRESS			
16. Physical progress (including reasons for any delays)			
17. Financial cashflows			
18. Expected start/end date			
OTHER			
19. Major comments/concerns expressed during public consultation			
20. Status of negotiations/agreements with stakeholders in neighboring countries (when applicable)			
21. CBCA (when applicable)			
22. Status of project in neighboring country (or countries) when applicable			

: provision of information not absolutely necessary

13. Monitoring the TYNDP Implementation

It is **recommended** that NRAs request TSOs to add an additional element in each TYNDP (within Section 4 of the recommended structure) describing the implementation performance with respect to the previously approved TYNDP in the period already elapsed. Further, or alternatively to this, a separate TYNDP implementation monitoring report may be requested from the TSOs on an annual basis, with details of analysis showing project progress and project impacts (if they have been recently commissioned). NRAs often request monitoring at biannual (or even quarterly) intervals for very significant electricity transmission projects.

13.1 Monitoring and Enforcement Procedures

The annual implementation monitoring reports must compare the actual versus planned progress of each electricity transmission project at the time of review and explain the reasons for each potential delay.

If a TSO does not execute an investment, the NRA is empowered through Directive 2009/72/EC, concerning common rules for the internal market in electricity (Article 22), to take one of the following measures:

1. Require the TSO to execute the investment in question;
2. Organize an open tender procedure for the investment in question; and
3. Oblige the TSO to accept a capital increase to finance the necessary investments and allow independent investors to participate in the capital.

In addition, the NRA may also impose penalties to the TSO for not fulfilling its responsibilities. It is noted that the NRAs of the United Kingdom and Greece are currently contemplating resorting to these measures to expedite the execution of long-delayed planned electricity transmission network investments.

Alternatively, Article 37 (paragraph 8) of Directive 2009/72/EC empowers NRAs to ensure that TSOs are granted appropriate incentives, over both the short and long term, to increase efficiencies and foster market integration and SoS (i.e., implement related investments). Such incentives may link TSO returns to overall societal benefits. The following best practice cases of regulatory incentives have been identified in a related EC-financed study, which, if applied, may reduce the risk of investments not being executed:[12]

- Increase in weighted average cost of capital for investments in new technologies that store electricity to help offset unknown operating expenditure risks in Italy;
- Early recognition of costs to address liquidity risks during the project construction phase in Italy;
- Use of a sliding scale adjustment mechanism to offset the risk of under-recovery of costs (volume risk) in Germany;
- Provision of clear rules and advice over anticipatory investments to avoid the development of projects with stranded costs in the Czech Republic;

[12] "Study on Regulatory Incentives for Investments in Electricity and Gas Infrastructure Projects." 2014. https://ec.europa.eu/energy/sites/ener/files/documents/MJ0614081ENN_002.pdf

- Ability to retain any capital expenditure cost savings achieved during the development and construction phases of projects in Portugal;
- Use of longer regulatory periods to help avoid investments becoming inefficient in Croatia;
- Use of an operational expenditure sliding scale mechanism to address cost overruns in the United Kingdom; and
- Use of a cap and floor revenue regime for new interconnection projects in the United Kingdom.

ACER has studied the most frequently mentioned reasons for delays in the implementation of large electricity transmission projects (European Projects of Common Interest) in 2016 and concluded that the permit granting process is a large contributor. Permitting often takes longer than expected, because of national law changes, environmental problems, or the involvement of several countries.

13.2 Monitoring Information

The present status and expected completion date of each project scheduled for initiation/implementation with respect to the previous approved TYNDP must in particular be identified in the TYNDP (e.g., under study, planned, approved, design/permitting, under construction, commissioned, re-scheduled, etc.). The evolution performance of each project must also be identified (e.g., on-time, delayed, or ahead-of-time, rarely).

With regard to the status of projects, it is noted that ACER has published an Opinion (no. 5/2015) that defines more detailed progress steps, including:

Planning

- preliminary design studies;
- preliminary investment decision;
- public consultation process;

Design/Permitting

- financing;
- cost allocation;
- decision on third-party access;
- detailed design; and
- tendering.

The following template for the uniform monitoring of projects by the TSOs is **recommended** (with the indicative example regarding the same 2017–2026 Kosovo TYNDP project provided earlier in Section 3 of this guide) to ensure their efficiency and effectiveness.

Project Title:	*SS Dragash and 110-kV line Kukës - Dragash - Prizren 2*	
Project Code:	……	
Purpose:	• *Qualitative and reliable supply of Dragash region* • *Reduction of power flows in SS Prizren 1* • *Optimization of operation of systems of Kosovo and Albania*	
Category:	*Resilience/efficient expansion/market functioning*	
Performance Criterion	**Planned**	**Actual**
Cost Analysis:	*SS Dragash, 2 110-kV transformation fields, one 10 (20)-kV and one 35-kV, two field lines, and one connection field of 110 kV: …… Euro*	…
	Single line, 8 km in length, Al/St 240 mm² from SS Prizren 2 to Zhur (dual pillars): …… Euro	…
	Dual line, 13 km in length, Al/St 2×240 mm² from Zhur to SS Dragash: …… Euro	…
	Single line, 26 km in length, Al/St 240 mm² from Zhur to Kukës (9 km from Zhur to the border): …… Euro	…
	Total Investment Cost: …… Euro	…
	Annual Maintenance Cost: …… Euro	…
	Total 25-Year Life-Cycle Cost: ……	…
Quantified Benefits:	*ENS: …… MWh annually*	…
	AIT: …… minutes annually	…
	Losses Reduction: …… MWh annually	…
	Network Capacity Increase: …… MW	…
	Avoided Peaking Generation: …… MW annually	…
	GTC to/from Albania: …… / …… MW	…
Permitting Status:	*No additional permits required*	*Commissioned*
Expected Commissioning Date:	*Fourth quarter of 2018*	*2018 / On-time*
Changes in Dependent Projects:	*None*	
Changes in Complementary Projects:	*None*	
Changes in Technical Description:	*None*	
Changes in Cybersecurity Considerations:	*None*	
Changes in Environmental Impact:	*None*	
Changes in Risks and Uncertainty:	*None*	
Changes in Topographical Map:	*None*	
Changes in Single-line Diagram:	*None*	

It is noted that whereas the project implementation costs can be accurately measured, the actual benefits realized cannot be immediately measured for each project. They will therefore most probably be initially presented by the TSOs in the same manner as in their initial TYNDPs (i.e., estimated from network simulation studies or past network performance). NRAs may request the TSOs to provide accurate benefit (e.g., losses) measurements for a sample of large projects. These measurements may be obtained through evidence provided by the TSOs through detailed analysis of SCADA system information or the placement of load analyzers at appropriate locations and time intervals (before and after project implementation). NRAs may also decide to independently perform (or outsource the performance of) a limited sample of on-site inspections of large implemented projects to verify implementation quality and benefits (e.g., environmental).

It is **recommended** that NRAs also monitor the implementation performance of the annual objectively verified transmission quality indicator targets set for the TSOs (i.e., regarding ENS, AIT, system minutes, etc.), although these are not solely attributable to the TYNDP.

13.3 Checklist for Regulatory Appraisal

The NRA must monitor the implementation of the previous TYNDP (presented in Section 4 of the recommended structure). Particular issues to consider are:

1. Review of permitting status of already identified projects;
2. Comparison of actual versus planned implementation time-table of commissioned projects;
3. Analysis of actual versus planned cost of implemented projects;
4. Analysis of estimated or actual (measured) versus planned benefits from implemented projects;
5. Reduction of annual ENS since previous TYNDP;
6. Reduction of annual AIT since previous TYNDP; and
7. Reduction of system minutes since previous TYNDP.

Annex 1: Example of CBA and Sensitivity Analysis

An example of CBA for a fictitious electricity transmission project is presented using indicative data.

Project Description

The project under examination is an investment in a 400-kV direct current underwater electric cable, including essential equipment and/or installations, for interconnecting the national transmission networks of two neighboring countries, country A and country B (the "Project"). The interconnector will have capacity of 2,000 MW and a total length of 500 km, and allow for reverse transmission of electricity. The Project is expected to be commissioned in 2020. The initial investment cost of the Project in year 0 is estimated at €1.5 billion, and the O&M costs from year 1 onward are assumed to be 1 percent of the initial cost, that is, €15 million annually. The horizon of the analysis coincides with the Project's technical life (or life cycle) of 40 years.

The Project's primary impact will be to improve market functioning by increasing GTC across the boundary, which in this case coincides with the international border. The Project is expected to increase GTC between the two countries by 2,000 MW in both directions. The impact of a project on GTC is a key input to the analysis and is calculated by performing network studies. Alternatively, net transfer capacity (NTC) can be estimated, based on GTC minus a margin (e.g., 10 percent), which is reserved to ensure system security.

Scenario Description

The analysis considers two study horizons: 2020 and 2030. For each country, a single scenario is examined for 2020, and two alternative scenarios are examined for 2030 (Scenario I and Scenario II). Values for intermediate years are estimated through interpolation. Scenarios are characterized by:

- a specific generation portfolio, and
- a demand forecast.

It is assumed that the examined system (countries A and B) is isolated, thus exchange patterns with other systems do not enter the analysis. Each scenario results in different future challenges for the grid. The differences between Scenario I and Scenario II concerning year 2030 are driven by policy, regulatory, and market developments that are reflected in:

1. the expected installed generation capacity and associated generation costs,
2. the cost of fuels, and
3. the cost of CO_2 emissions.

Indicative figures for these variables are presented next. Specifically regarding the generation capacity that is associated with the generation portfolio of each scenario in country A, indicative figures are shown.

Net Generating Capacities (MW)—Country A

Indicative	Hydro	Gas	Lignite	Solar	Wind
2020 Scenario	3,669	5,202	2,876	4,000	2,800
2030—Scenario I	4,259	3,111	2,876	4,050	4,880
2030—Scenario II	4,366	6,252	1,070	8,384	12,335

It is further assumed that each plant type (hydro, gas, lignite, solar, and wind) has a specific constant marginal cost of production. In the marginal cost of production, only short-term costs are taken into account, with three main components:

- Fuel costs,
- Variable operating costs, and
- CO_2 costs (where applicable).

Indicative figures for marginal costs of each generation technology in each scenario in country A are shown.

Marginal Cost of Production (€/ MWh)—Country A

Indicative	Hydro	Gas	Lignite	Solar	Wind
2020 Scenario	50	10	30	17	15
2030—Scenario I	65	10	28	17	15
2030—Scenario II	90	10	120	17	15

Finally, an indicative demand forecast per hour of the year (MW) in each scenario in country A is shown.

Marginal Cost of Production (€/ MWh)—Country A

Indicative	1	2	3	4	5	6	…	…	8,755	8,756	8,757	8,758	8,759	8,760
2020 Scenario	5,635	5,239	5,123	4,826	4,542	…	…	…	…	7,274	7,204	6,959	6,525	6,247
2030—Scenario I	6,428	5,901	6,017	5,727	5,436	…	…	…	…	7,722	7,649	7,393	6,927	6,719
2030—Scenario II	7,095	6,435	6,780	6,497	6,199	…	…	…	…	8,078	8,003	7,736	7,245	7,112

A key assumption for the analysis is that demand is fully price inelastic, that is, demand does not vary at all with the price of electricity.

Modeling Simulations

Market Simulation

Market simulation is used to calculate the minimum cost dispatch of generation units, market exchanges between country A and B, and corresponding marginal costs on an hourly basis. It is required to estimate the project's effect on SEW, including the project's effect on CO_2 emissions and RES integration. Whenever the country's market price (€/MWh) is above a plant's marginal cost, the plant is operated at full available capacity. If the price is below the marginal cost, there is no production at all. If the marginal cost and the market price coincide, then the level of production is at the level where total supply and demand in the country are equal. Cross-border trade between country A and B takes place on an hourly basis through the interconnector from A (less expensive) to B (more expensive). The output of the simulation model is a set of electricity prices for each hour of the year and for each country of the system (country A and country B) at which all of the following hold:

- Prices (net of any direct transmission costs) in A and B are equal, or transmission capacity of the interconnector is reached;
- In country A, electricity produced is in balance with electricity consumed and exported; and
- In country B, electricity produced and imported is in balance with electricity consumed.

Network Simulation

Network simulation is used to identify bottlenecks in the grid corresponding to the power flows resulting from market exchanges, that is, the results of the market simulation. Its output and the resulting estimate of the project's impact on GTC (or NTC) across the boundary also feeds as an input to the market simulation model. So, network simulations are used iteratively with market simulations.

Models for network simulation represent the transmission network in a high level of detail and calculate actual load flows in the network under given generation, load, and market conditions. These are required to estimate a project's impact on:

- GTC (or NTC) between A and B, which is necessary input to market simulation;
- System losses; and
- SoS, that is, the risk of not covering the demand by production or import; this is performed by assessing the impact of different events/contingencies via Monte Carlo analysis.

Economic Benefit Indicators

As a result of these simulations, on the basis of the assumptions and input described, a number of economic benefits resulting from the Project are estimated in monetary terms.

Socioeconomic Welfare (SEW)

The SEW indicator estimates the impact of the project on total electricity generation costs in countries A and B for each of the examined scenarios, on the basis of market simulation and analysis. The Project under examination increases GTC between A and B, and allows generators in A (lower priced segment) to supply power to B (higher priced segment). As shown in the next table, the effect of power exports from country A to country B, in all scenarios, is that:

- Average generation costs in country B increase as production by the less efficient generation plants of country B (in terms of fuel, operational, and CO_2 costs) ceases and part of domestic demand in country B is catered by power imports from country A;
- Average generation costs in country A increase as the less efficient plants of country A enter production to cater for additional demand from country B; and
- Average generation costs in the system/region are reduced, hence increasing overall SEW.

Project Impact on SEW

Indicative	Demand—A (GWh/yr)	Demand—B (GWh/yr)	Average generation cost (EUR/MWh)						Economic benefit (€ mil/yr)
			Without Project			With Project			
			A	B	System	A	B	System	
2020 Scenario	53,244	17,517	39.00	55.00	55.00	39.30	39.50	39.50	192
2030—Scenario I	56,825	21,495	41.00	60.00	60.00	41.50	42.00	42.00	260
2030—Scenario II	59,808	24,640	54.00	80.00	80.00	55.00	56.00	56.00	376

System Losses

At constant power flow levels, network development projects such as the one under examination generally decrease losses. Additionally, projects that aim to make the transmission system more meshed result in a reduction of electrical distance between production and consumption and, as a result, a reduction in losses. However, projects that support integration of RES tend to increase losses because of the resulting transmission of energy over longer distances from renewable generation installations toward the load centers. In the indicative Project, as shown in the next table, this leads to an overall increase in system losses in both countries and in all three scenarios, as estimated through network simulation and analysis. These are monetized using the marginal cost of electricity in the respective scenarios in each country.

Project Impact on System Losses

Indicative	Change in losses (GWh/yr)		Marginal cost of electricity (EUR/MWh)		Economic benefit (€ mil/yr)		
	A	B	A	B	A	B	Total
2020 Scenario	300	200	47	60	-14	-12	-26
2030—Scenario I	240	160	51	67	-12	-11	-23
2030—Scenario II	480	320	66	83	-32	-26	-58

RES Integration and CO_2 Emissions

The Project's impact and benefits in terms of facilitating RES integration and contributing to reduction of CO_2 emissions are already internalized in the SEW benefit indicator, and should not be accounted twice. However, they can be estimated (through market studies) to provide a more complete picture and to facilitate understanding and interpretation of impacts associated with the Project. As shown in the next table, the Project leads to a reduction in CO_2 emissions in the two 2030 scenarios, as the interconnector enables low-carbon generation plants in country A to produce more electricity, thus replacing conventional plants with higher carbon emissions in country B. Additionally, the Project leads to an increase in RES integration capacity in all three scenarios because it enables transportation of energy generated by RES in country A with RES production surplus, which would have otherwise been curtailed, to country B where thermal generation is more prominent.

Project Impact on RES Integration and CO_2 Emissions

Indicative	Change in RES integration capacity (GWh/yr)	Variation in CO_2 emissions (kT/yr)
2020 Scenario	250	0
2030—Scenario I	1,500	-5,000
2030—Scenario II	2,000	-2,500

> *Note: The SoS benefit of the Project in this example is assumed to be negligible, which tends to be the case for new projects that are integrated into well-meshed networks.*

Economic Costs and Analysis Indicators

Economic Costs

Economic costs should reflect social opportunity costs that may not be reflected on financial costs. For example, the opportunity cost of employment may differ from the financial cost. Thus, in the CBA, the evaluation should be based on shadow prices, or prices that reflect the true economic opportunity cost of resources. Nevertheless, in this example, it is assumed, as is often the case, that the Project's cost estimates adequately reflect social opportunity costs and are thus used in the CBA.

As shown in the next table, the economic cost per year is calculated as the sum of O&M costs of the Project and of the initial investment's capital expenditure. The present value (PV) of economic cost per year is estimated using the following formula and an economic discount rate (EDR) of 4 percent:

$$PV\ of\ Year\ n\ Economic\ Cost = \frac{Year\ n\ Economic\ Cost}{(1 + EDR)^n}$$

Summing the PV of economic costs per year arrives at the PV of total economic costs, which in this case is estimated at €1,797 million.

Project Economic Costs

(€ million)	Year									
	0	**1**	**2**	**3**	**4**	**5**	**10**	**20**	**30**	**40**
O&M Costs	-	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0
Investment Cost	-1,500	-	-	-	-	-	-	-	-	-
Economic Cost	-1,500	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0
PV of Economic Cost	-1,500	-14.4	-13.9	-13.3	-12.8	-12.3	-10.1	-6.8	-4.6	-3.1

PV (€ mil)	**-1,797**

Analysis Indicators

The two economic benefit indicators, which are considered in the final analysis indicators, are SEW and system losses. As discussed earlier in this section, the values for these indicators are estimated for year 1 ("2020 Scenario") and year 10 of the analysis ("2030—Scenario I" and "2030—Scenario II"). For intermediate years, the indicator values are estimated via interpolation, assuming a linear trend (i.e., of constant change per year) between the year 1 and the year 10 value. From year 10 onward, the indicator values are assumed to remain constant.

The analysis indicators for the 2030 Scenario I are shown in the next table. Summing up the two economic benefit indicators and deducting economic costs yields the net economic benefits. The PV of net economic benefits per year is estimated using the following formula and an EDR of 4 percent:

$$PV\ of\ Year\ n\ Net\ Economic\ Benefit = \frac{Year\ n\ Net\ Economic\ Benefit}{(1 + EDR)^n}$$

By summing the PV of net economic benefit per year, we arrive at the ENPV of the Project, which in this example is estimated at €2,566 million. By estimating the EDR value for which ENPV is zero, we arrive at the Project's ERR, which in this example is 13 percent.

Analysis Indicators—2030 Scenario I

(€ mil)	Year									
	0	1	2	3	4	5	10	20	30	40
SEW	-	192	199	206	213	219	260	260	260	260
System Losses	-	-26	-26	-25	-25	-25	-23	-23	-23	-23
Economic Cost	-1,500	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0
Net Economic Benefits	-1,500	151	158	165	173	180	222	222	222	222
PV of Net Economic Benefits	-1,500	145	146	147	147	148	150	101	68	46

ENPV (€ mil)	**2,566**

ERR (%)	**13%**

Similarly, the analysis indicators for the 2030 Scenario II are shown next.

Analysis Indicators—2030 Scenario II

(€ mil)	Year									
	0	1	2	3	4	5	10	20	30	40
SEW	-	192	211	229	248	266	376	376	376	376
System Losses	-	-26	-29	-32	-36	-39	-58	-58	-58	-58
Economic Cost	-1,500	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0
Net Economic Benefits	-1,500	151	166	182	197	212	303	303	303	303
PV of Net Economic Benefits	-1,500	145	154	162	168	174	205	138	94	63

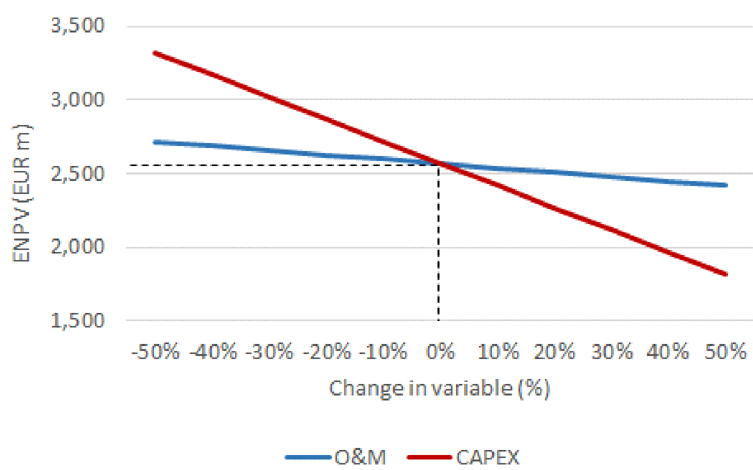
ENPV (€ mil)	**3,798**
ERR (%)	**15%**

Therefore, the Project's ENPV is estimated to range between €2,566 and €3,798 million, while the Project's ERR is estimated to range between 13 percent and 15 percent as compared to a discount rate of 4 percent. Thus, the Project is deemed to be highly beneficial from society's perspective and should be implemented.

Sensitivity Analysis

Under the 2030 Scenario I, the Project's ENPV is estimated at €2,566 million. As shown in the next figure, ENPV is robust to changes in the range of +/- 50 percent in O&M and CAPEX. Specifically, ENPV is more elastic (i.e., more responsive to changes) with respect to CAPEX (-0.6), as a 10 percent increase in CAPEX would lead to 6 percent drop in ENPV. ENPV is less elastic with respect to O&M (-0.1), as a 10 percent increase in O&M costs would lead to 1 percent drop in ENPV.

2030 Scenario I Sensitivity Analysis



The switching values of ENPV with respect to the two variables are:

- CAPEX: +171 percent (i.e., CAPEX must be 1.7 times higher than its estimated value for ENPV to switch to zero);

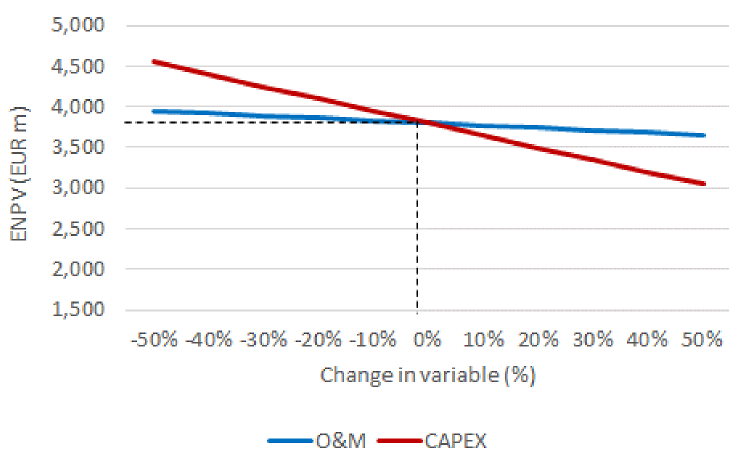
- O&M: +864 percent (i.e., O&M must be 8.6 times higher than its estimated value for ENPV to switch to zero).

Thus, based on the analysis of switching values, the Project is assessed to be nonrisky.

Even in a highly pessimistic scenario in which both O&M and CAPEX are higher than their respective estimated amounts by 100 percent, ENPV remains positive at approximately €769 million. Thus, based on the scenario analysis, the Project is again assessed to be nonrisky.

Under the 2030 Scenario II, the Project's ENPV is estimated at €3,798 million. As shown in the next figure, ENPV is robust to changes in the range of +/- 50 percent in O&M and CAPEX. Specifically, ENPV is more elastic with respect to CAPEX (-0.4), as a 10 percent increase in CAPEX would lead to 4 percent drop in ENPV. ENPV is less elastic with respect to O&M (-0.1), as a 10 percent increase in O&M costs would lead to a 1 percent drop in ENPV. Even in the extreme scenario that CAPEX is 50 percent than the estimated amount, ENPV would remain positive at approximately €3 billion.

2030 Scenario II Sensitivity Analysis



The switching values of ENPV with respect to the two variables are the following:

- CAPEX: +253 percent (i.e., CAPEX must be 2.5 times higher than its estimated value for ENPV to switch to zero);
- O&M: +1,279 percent (i.e., O&M must be 13 times higher than its estimated value for ENPV to switch to zero).

Thus, based on the analysis of switching values, the Project is assessed to be nonrisky.

Even in a highly pessimistic scenario in which both O&M and CAPEX are higher than their respective estimated amounts by 100 percent, ENPV remains positive at approximately €2 billion. Thus, based on the scenario analysis, the Project is again assessed to be nonrisky.

Annex 2: MCA for Project Prioritization

When ranking of projects requires the assessment of more than one criteria, then MCA is the approach typically applied because it allows to assess the trade-offs of the projects and to result in quantitative ratings under criteria of different relative importance.

The key features of MCA are the same regardless of the decision-making case in which they are applied. They include:

- *Alternative options*: The options that the decision makers are called to compare. In this case, the options are the proposed projects.
- *Decision tree*: Hierarchical representation of the criteria to be used, which facilitates the evaluation of the alternative options. The criteria may be further divided into subcriteria, resulting into a decision tree of multiple levels. The evaluation of the options is always performed at the lowest available level for each "branch" (i.e., criterion ≥ level 1 subcriterion ≥ level 2 subcriterion, etc.) of the tree. As a basic principle, proper application of the MCA requires that all criteria be "mutually preference independent," that is, scores assigned to all options on one criterion are unaffected by the preference scores on the other criteria.
- *Weights*: Numerical values are assigned to define the relative significance/preference of each criterion and subcriterion. Local weights are the relevant weights of the group of criteria/subcriteria deriving from a criterion. The local weights express the different preference among the criteria or subcriteria belonging to the same group. Global weights are calculated as the product of local weights along each "branch" of the decision tree. The global weights, which express the overall significance of the lowest level criteria/subcriteria, are used for the calculation of the overall rating/scoring of the projects.
- *Rating/Scoring of options*: The expected performance or consequence of each option on each lowest level criterion/subcriterion is assigned a numerical score on a quantitative scale/qualitative, which indicates the level of impact that the specific option has on the criterion/subcriterion.

The above features are practically applied through large numbers of multicriteria calculation methods, each addressing decision-making cases of different nature, complexity, and characteristics. For the case of ranking electricity transmission investment projects, the most commonly used multicriteria calculation method is the weighted sum method, a simple and linear scoring method.

Ranking of projects with the weighted sum method entails the following steps:

1. Definition of the evaluation criteria (and subcriteria if required);
2. Assignment of weights to the criteria and subcriteria (see next for details). If subcriteria are being used, then the global weight of each subcriterion is estimated;
3. Definition of scoring approach and scale for each criterion;
4. Scoring of examined projects for each criterion;
5. Normalization of scores, so that the values for all criteria are within the same range (e.g., between 0 and 1). For normalization, usually all project scores are compared to a fixed maximum and a minimum value per criterion, using the following formula:

$$\frac{(score - \min)}{(\max - \min)}$$

6. The weighted sum of the project's scores is calculated to define its final rating, which is used for ranking. The formula applied to calculate the final rating is the following:

$$\sum_{i=1}^{n} w_i \; x \; ns_i$$

where n is the number of criteria, w_i is the weight of criterion i, and ns_i the normalized score of criterion i. If subcriteria have been used, then w_i is the global weight of the relevant subcriterion.

The graphic representation of the criteria scores on a spider diagram is often used as part of MCA, so as to facilitate decision makers in assessing the strengths and weaknesses of each alternative option. Assignment of weights to criteria is crucial for the final outcome of the projects' ranking. In this respect, the weights must be carefully set, using a formalized, clear and transparent approach. A method that has been widely used for setting weight when ranking infrastructure projects is the AHP.

The application of AHP for setting of weights involves pairwise comparisons of the criteria or subcriteria belonging to the same group that expresses the relative importance of one particular criterion relative to another. For each pairwise comparison, the decision maker assigns an integer value on a scale 1–9, with 1 denoting criteria of equal importance and 9 extreme importance of the one criterion over the other as depicted in the next table. To ensure consistency, the reciprocal of this value is assigned to the other criterion in the pair. The values are used to structure a pairwise comparison matrix that includes all compared criteria, and the weight of each criterion is then calculated using the eigenvectors of the matrix.

Value of comparing criteria *a* and *b*	**Interpretation**
1	*a* and b are equally important
3	*a* is slightly more important than *b*
5	*a* is more important than *b*
7	*a* is strongly more important than *b*
9	*a* is absolutely more important than *b*
2, 4, 6, 8	Intermediate values

A preference matrix example for the assignment of weights using the AHP method to the categories of transmission project benefits identified by ENTSO-E is presented next, resulting in the average weights for each benefit concluded in the normalized preference matrix following. It is noted that a systematic consistency analysis may also be undertaken before acceptance of the average preference rates.

Preference Matrix

	SEW	RES integration	Improved SoS	Losses variation	CO_2 mitigation	Technical resilience	Flexibility
SEW	1	3	1/6	1/5	4	1/4	1/3
RES integration	1/3	1	1/8	1/7	2	1/6	1/5
Improved SoS	6	8	1	2	9	3	4
Losses variation	5	7	1/2	1	8	2	3
CO_2 mitigation	1/4	1/2	1/9	1/8	1	1/7	1/6
Technical resilience	4	6	1/3	1/2	7	1	2
Flexibility	3	5	1/4	1/3	6	1/2	1

Normalized Preference Matrix

	SEW	RES integration	Improved SoS	Losses variation	CO_2 mitigation	Technical resilience	Flexibility	AVERAGE %
SEW	0.05	0.10	0.07	0.05	0.11	0.04	0.03	**6.25**
RES integration	0.02	0.03	0.05	0.03	0.05	0.02	0.02	**3.28**
Improved SoS	0.31	0.26	0.40	0.46	0.24	0.42	0.37	**35.40**
Losses variation	0.26	0.23	0.20	0.23	0.22	0.28	0.28	**24.26**
CO_2 mitigation	0.01	0.02	0.04	0.03	0.03	0.02	0.02	**2.37**
Technical resilience	0.20	0.20	0.13	0.12	0.19	0.14	0.19	**16.70**
Flexibility	0.15	0.16	0.10	0.08	0.16	0.07	0.09	**11.74**

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