



TRANSMISSION NETWORK INVESTMENT CRITERIA



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EXECUTIVE SUMMARY

Introduction

Transmission network planning has been strongly influenced by the electricity market opening. Several facts are very important for transmission planning process under new conditions. These facts are:

- significant uncertainties that appear in a deregulated environment comparing to those that appear in a non-deregulated monopolistic environment,
- lack of input data needed for planning process,
- different transmission development objective functions, depending on the view of market players and participants (producers, traders, suppliers, consumers, regulators, operators),
- certain disproportion between technical, economical, environmental and social requests.

In the SEE region transmission network is owned and controlled by SEE TSOs. Area of interest for this Study spreads over territories of Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Macedonia, Montenegro, Romania, Serbia, UNMIK, Slovenia and Turkey. Each of them has its own transmission system operator who is responsible for network reliability and security, as well as operational and planning aspects.

The 8th Athens Forum concluded that transmission investment criteria have to be defined from a regional perspective, and transmission projects have to be prioritized according to those criteria. The aim of that conclusion is to support market activities inside the Energy Community and to remove barriers caused eventually by transmission network for free market trading.

This study elaborates the problem of transmission investments in an open market environment (Chapter 2) defining the most relevant uncertainties in the SEE region, reviews past experience in transmission network planning, analyzes transmission planning criteria which have been used by different SEE TSOs (Chapter 3), reviews national grid codes and a draft version of the regional grid code (Chapter 4), suggests transmission investment criteria from a regional perspective and proposes a methodology for project prioritization (Chapters 6 and 7), based on the certain prerequisites and assumptions (described in Chapter 5).

Transmission network planning in an open electricity market

Transmission network planning inside the vertically integrated power companies were mostly performed in order to determine network configuration in the future that will support power plants economical dispatch and satisfy predefined technical requests with minimum construction, operation and maintenance costs. Transmission network planning inside the SEE power supply companies in the past was characterized by the following:

- (n-1) criterion was applied and was dominant in planning,
- only peak load situations were analyzed (minimum load situations were also analyzed somewhere to observe voltage profile),
- probabilistic methods were generally not used, so probability of network failures and overloadings were not observed,

- economical criteria were not dominant in decision making process,
- uncertainties in input data (production plan, generators dispatch, load growth, etc.) and related risk of wrong investments were not treated satisfactorily.

In an open market environment there are significant uncertainties, which have to be taken into account during transmission system planning. The most significant uncertainties are:

- power plants construction,
- power plants decommission,
- generators engagement (bidding behavior),
- load growth predictions,
- demand elasticity,
- market prices,
- market transactions,
- bilateral contracts,
- regulatory aspects,
- market organization, etc.

There are some important issues which have to be considered concerning transmission system planning in an open market environment:

- network planning has to include the most important uncertainties in the future,
- traditional mathematical optimization methods and deterministic models are not appropriate for market conditions without significant improvements,
- each network investment decision include some risk, so risk analysis techniques should be applied in network planning,
- investment decisions depend on applied planning criteria which should be defined according to a strategic view on transmission role in the market (economically optimal or satisfactory secure network, allowance of full competition no matter of development costs etc.),
- having in mind the necessity for uncertainties inclusion in the planning process, risk analysis and economical calculations, the probabilistic planning methods have advantages comparing to deterministic ones,
- network development in an open market conditions should be initiated by market oriented signals such as location marginal pricing or congestion costs.

Today, the SEE TSOs still plan their networks as before, without taking into consideration future market conditions. Technical (n-1) criterion is still the main rationale for network strengthening, the economic criteria have not been applied, the deterministic methods have been dominantly used, almost neither of them use probabilistic methods (except Romania), uncertainties have not been included into the planning process, there are not enough, or not at all, market signals which may lead to network investments.

Existing planning criteria

Based on the questionnaire that was given to eleven SEE TSOs (Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Macedonia, Montenegro, Romania, Serbia, UNMIK, Slovenia and Turkey) about transmission network planning issues, it may be concluded that:

- SEE TSOs are responsible for transmission network planning, and development plans have to be approved by national regulatory authorities everywhere;
- SEE TSOs are obliged by national laws to prepare transmission development plans up to 20 years ahead. The most often time horizons for planning are 1 year ahead and five years ahead;
- Transmission investments are mostly financed through transmission fees and loans. Only Turkey allows private investors to construct transmission facilities;
- Transmission planning criteria are published in the national grid codes;
- The main technical criterion for transmission system development is the (n-1) security criterion, which is applied everywhere. It is mostly related to the loss of single line, transformer or generator, when following events are not permitted:
 - thermal overloadings of branches,
 - voltage declination below permitted range,
 - loss of stability,
 - loss of load,
 - interruption of power transits, and
 - disturbance spreading over power system.
- The (n-2) criterion is used only in Montenegro and Romania (in Romania only for grid connection of the nuclear power plant);
- Other technical criteria for transmission system planning are not used, except in Romania where stability criteria and compensation facilities installation criteria are prescribed;
- SEE TSOs usually do not define different thermal ratings for winter and summer operational circumstances, or for normal and emergency conditions. Different ratings are defined somewhere (Albania, Montenegro, Serbia, Turkey, UNMIK) for winter and summer operation with respect to the outside temperature, and different ratings are defined somewhere for normal and emergency conditions with respect to the protection systems settings (Macedonia, Montenegro, Slovenia);
- There are no TSOs in the SEE which value the probability of the (n-1) events during transmission system planning;
- SEE TSOs usually conduct load flow computations, security analysis and short circuit calculations during planning process. Optimal power flows (Bulgaria, Turkey, UNMIK) and stability analysis (B&H, Bulgaria, Macedonia, Romania, Turkey) are also conducted somewhere;
- Probabilistic analyses during transmission system planning process are performed only in Romania;

- Economic criteria are applied somewhere (Albania, B&H, Croatia, Macedonia, Romania, Serbia, UNMIK) in the transmission network planning;
- The most often used economic criterion is the profitability index as the ratio between benefits and costs of transmission investments;
- SEE TSOs which apply an economic criterion usually estimate reduction of the cost of losses, loss of load costs, re-dispatching costs, congestion costs and benefit from telecommunication lines;
- Undelivered electricity costs in the SEE are lower than 3 €/kWh. The lowest value is applied for planning purposes in UNMIK (0.4 €/kWh), and the highest value is applied in Croatia (2,56 €/kWh). Some countries have not defined those costs;
- Generally, additional planning criteria are not applied for interconnection lines. Some countries apply different planning criteria based on the system operational costs (Macedonia) and difference between energy prices (Serbia);
- Uncertainties are mostly taken into account by using multi-scenario analysis (Table 4). The most important uncertainties are:
 - new power plants size and location,
 - generators engagement,
 - hydrological conditions,
 - market transactions,
 - country power balance (demand/supply).
- Risk assessments are not conducted by the SEE TSOs.

Grid codes review

Based on the review of the national grid codes and a draft version of the regional grid code related to the transmission network planning issues, it can be concluded that:

- Grid codes prescribe TSOs obligations related to transmission system planning reports and studies. Planning horizons vary from short-term (up to 1 year ahead) to long-term (up to 20 years ahead);
- Grid codes define the role of the transmission systems. National transmission systems have to enable reliable and secure system operation and continuous load supply. Regional aspects of national transmission systems are not mentioned in national grid codes so there is no reference point for regional transmission system planning;
- All national grid codes prescribe the usage of the (n-1) criterion in transmission system planning. Explanation of that criterion is very similar between countries and not permitted consequences of single outages are pretty much the same;
- Other technical criteria, such as short-circuit or stability criteria, are prescribed somewhere in national grid codes;
- Transmission investments economic rationalization is not mentioned in the national grid codes, except in general terms in B&H and Romanian ones;
- Probabilistic technical criteria for transmission system planning (loss of load probability) are mentioned only in Romanian and Turkish grid codes;

- National grid codes are prepared in line with a draft version of the regional grid code, and there are no larger disproportions between the national grid codes and the regional grid code concerning transmission system planning issues;
- Draft version of the regional grid code assumes creation of a working group which would plan the network on a regional level, especially directing attention towards interconnection lines and those internal lines that have large impact on transfer capacities between different countries. National grid codes do not envisage any working group at a regional level which may deal with regional and/or national transmission system planning issues;
- It seems that national grid codes and a draft version of the regional grid code do not satisfactorily respect market issues in transmission planning, especially concerning planning uncertainties, economic considerations of transmission investments, balance between security and costs, promotion of the private financing and congestion costs.

Prerequisites and assumptions

The basic assumption for the work conducted within this Study is that the regional electricity market will exist in the near future at the territory of South East Europe. Planning criteria and methodology are thus suggested to be respected by the SEE TSOs.

Well defined planning criteria and methodology at the regional level may help the SEE countries to develop their power systems and infrastructure that will serve common electricity market in accordance with the Energy Policy for Europe (EPE). Meeting the objectives from the EPE related to sustainability, competitiveness and security of supply will surely help the SEE countries to better integrate into future common European electricity market.

Basic assumption for the work conducted in this Study is that a stable regulatory framework and necessary degree of co-ordination between the SEE TSOs in terms of technical standards, balancing rules and congestion management mechanisms will be achieved in the near future. More sufficient unbundling of the TSOs from production and supply companies may lead to more incentives to develop the network in the overall interest of the market and the SEE region as a whole.

The SEE transmission network planning criteria and methodology are defined by observing national networks at the territory of the SEE, under the responsibility of the SEE TSOs, as unique network, with the aim to promote and ensure market activities inside the Energy Community. Planning criteria and methodology are defined taking into account national requests defined in national grid codes as much as possible, but suited to the regional electricity market needs. They serve primarily to support market activities with satisfactory level of overall system adequacy and security, based on technical and economical considerations. They also serve to estimate the level of future SEE power system reliability and to identify and prioritize transmission investment candidates from a regional point of view.

In other words, the SEE region is observed as one power system with same obligations and rights for all market participants and transmission network planning criteria and methodology are set to keep the overall system adequacy and security in the most economical way.

Important assumption for the effective usage of planning criteria and methodology proposed in this Study which will lead to transmission network investments with regional significance is an acceleration of authorization procedures (construction of a new transmission line may last more than 10 years in existing situation). Dynamic and fast development of the SEE transmission system

will support predicted fast growth of trading activities inside the electricity market and fast integration of renewable energy sources (construction period for a new wind power plant is up to three years), which will be impossible if complicated authorization procedures remain unchanged.

Environmental aspects in the SEE transmission system development have to be observed and respected in the most efficient manner. This will help to speed up the construction of transmission facilities by making them more acceptable for the public.

Private initiatives and public-private partnership in the SEE transmission system planning and development should be stimulated by market oriented signals. Private interest is important aspect with respect to economic rationalization of network investments and has to be respected and promoted.

The SEE transmission system planning should include the most important uncertainties that may arise in the future. According to the planning horizons (short, medium, long term planning), there are different types of uncertainties which have to be included in analyses. The most important uncertainties which should be observed in the network planning are:

- new power plants size and locations,
- hydrological conditions,
- generators bids,
- branches and generators availability,
- load prediction,
- regional power balance.

Different planning scenarios dependent on the uncertainties and planning time-frame are shown in Appendix 4.

Transmission network has to be designed to serve the needs of its consumers. Connection of new power plants brings probably the largest uncertainty in network development. As many as necessary scenarios concerning Generation Investment Plan have to be analyzed. In accordance to the European Energy Policy special attention should be directed on the integration of renewable sources into the grid. One generation investment scenario may be defined assuming high integration of renewable sources on distribution (small wind power plants, fuel cells, small hydro etc.) and transmission level (large wind power plants).

Transmission system investments are financed by the SEE TSOs through transmission fees and loans according to national legislation. National regulatory authorities have to approve network investments and allow the inclusion of investment costs into transmission fees. This study does not observe the problem of investments financing. Problems may arise if some SEE TSO is not satisfied with the SEE transmission system development plan, made according to the criteria and methodology defined here, and rejects to invest in some new line with a regional market significance (with not so obvious benefit for national network and system under control of that TSO). Some mechanism for investments financing on the territory of one TSO but beneficiary for other TSOs or market players/participants has to be found at least in the framework of the Energy Community. Otherwise, the adoption of planning criteria and methodology suggested in this Study will be more complicated, if not impossible. Private investments should be stimulated also by the SEE TSOs, regulatory authorities and respective EU bodies.

With the market development it is expected that congestion costs will become a very influential factor for interconnection lines construction. Nevertheless, transfer limits on interconnection lines in the SEE are often related to some internal network problems, and rationalization of some investments in new interconnection capacity may cause that internal problems stay hidden. Furthermore, the SEE TSOs may declare lower values of Net Transfer Capacity in order to protect domestic power producers from market activities or to keep unnecessary high level of security of a system under their control because of different reasons.

Having in mind that planning criteria and methodology are set in this Study for the SEE region as a whole, the treatment of interconnection lines and internal national lines should be the same. It means that suggested criteria and methodology have to be applied equally to interconnection lines between different SEE TSOs and to internal power lines inside national networks. Planning criteria for power lines between the SEE countries and other markets and power systems should be based on economical rationales, taking into account possibilities for expanding market activities (power import, export) and differences in electricity prices on different markets.

Transmission network investment criteria

Technical criteria for the SEE transmission system planning are used for technical evaluation of the candidate projects for transmission network reinforcements. Technical criteria include:

- 1) The (n-1) criterion,
- 2) Voltage and reactive power criterion,
- 3) Short-circuit criterion, and
- 4) Stability criterion.

Table 5 (Chapter 6.1.5) presents the summary of suggested SEE transmission system technical planning criteria.

The profitability index is defined as the ratio between expected annual benefit from a candidate project and the annuity of its expected costs (construction, operational and maintenance costs), and suggested as the economic criterion for transmission system planning. Profitability indices for candidate projects have to be calculated for all time frames (planning years) within the planning horizon. Observed candidate project is economically profitable if its profitability index is larger than 1 within planning period. If profitability index is not larger than 1 for all studied years a candidate project is considered as not economically profitable.

The most important transmission candidate project is the one with the highest value of the profitability index. Economically profitable transmission candidate projects should be included into planned network configuration according to declined profitability indices (from the highest profitability index of a candidate project to the lowest but greater than 1). Planned transmission network configuration should not contain any economically not profitable candidate project.

The following types of benefit from candidate projects construction may be estimated for the purpose of economic criterion evaluation:

- benefit due to reduction of expected annual undelivered electricity costs,
- benefit due to annual losses reduction,

- benefit due to reduction of annual re-dispatching costs,
- benefit due to annual congestion costs reduction.

The following types of costs from candidate projects construction may be estimated for the purpose of the economic criterion evaluation:

- investment costs,
- operation and maintenance costs.

For the planning purposes, investment costs may be estimated by using unit equipment price values. Unit equipment price values for the SEE region which will be used for planning purposes have to be determined by the SEE TSOs.

Discount rate which will be used for the SEE transmission system planning should be determined by relevant institutions (the SEE regulatory authorities, the SEE TSOs etc.).

Methodology for project prioritization

The SEE TSOs are obliged to plan transmission systems under their control. Their plans will include new facilities and objects, but planned primarily to satisfy their national requirements, obligations and criteria. Regional and market significance of these projects may be invisible or not estimated and taken into account. Unique list of candidate projects in the SEE should be determined and each of the SEE TSOs should define candidate projects according to their national plans and considerations. This list has to include technical and economical parameters of candidate projects. The list of candidate projects prepared by each SEE TSO shall be divided into two parts:

1. candidate projects with local significance, and
2. candidate projects with possible regional significance.

Only candidate projects with possible regional significance should be evaluated at the SEE regional level, examined according to pre-defined technical and economical criteria and prioritized according to the methodology defined in this Study.

Load flow and security analyses have to be conducted within planning time-horizon in order to examine future network operation and identify possible constraints that may occur. Network modeling for load flow and security analyses shall be prepared by the SEE TSOs, representing a network on the territory of their control. Models shall be merged and one official model of the SEE transmission network shall be prepared for each studied year within the planning horizon. Network shall be modeled in the PSS/E format (Power System Simulator for Engineers, Siemens PTI) that is used by all SEE TSOs. Concerning analyzed demand situations, three load levels shall be modeled:

1. winter peak load,
2. summer maximum load, and
3. summer minimum load.

Initial models should be used to create different models representing future uncertainties defined in Chapter 5.2 and Appendix 4.

Load flow and security analyses should be performed for all future scenarios and network constraints should be recorded. List of recorded network constraints for all analyzed planning scenarios in a studied year is the base for project candidates' technical and economical evaluation that follows.

For the purpose of economical evaluation of candidate projects, declared by the SEE TSOs as “projects with possible regional significance”, and their prioritization, probabilistic analysis should be performed. Probabilistic analysis should be conducted for different demand (load) levels. Probabilistic analysis should be performed for all planning scenarios defined according to future uncertainties. For each planning scenario benefits from candidate projects shall be evaluated.

Separate application of technical and economical criteria in transmission system development evaluation and projects prioritization procedures should be allowed, depending on readiness and availability of software tools.

Starting from the common list of candidate projects, nominated by the SEE TSOs as “projects with possible regional significance”, and conducted analyses of load flows and (n-1) security, candidate projects should be included into network topology one by one, and new load flow and security analysis have to be performed for all analyzed planning scenarios in a studied year. New list of network constraints has to be created, and constraints that are removed when new project is included into network topology have to be highlighted.

Candidate projects which are included in the reviewed list of candidate projects are technically prioritized according to network constraints that are removed by candidate projects:

- first group contains candidate projects that remove network constraints with (n) available branches (the highest level of technical prioritization), and
- second group contains projects that remove network constraints with (n-1) available branches (lower level of technical prioritization).

Inside these two groups of candidate projects, further technical prioritization is made according to:

- the number of planning scenarios in which a candidate project removes network constraints (more planning scenarios with network constraints that are removed by a candidate project, more technically significant is a project),
- voltage level of overloaded transmission lines (removal of overloadings on 400 kV lines are more significant than on 220 kV lines), and
- the number of network constraints that are removed by a candidate project (more constraints are removed, more technically significant is a project).

Candidate projects that are included in the reviewed list of candidate projects and prioritized according to the technical criteria should be further evaluated and prioritized according to the economic criteria.

Evaluation and prioritization of candidate projects according to the economic criteria is based on the profitability indices, or on the basis of the ratio between annual expected projects benefit and costs annuity for a studied year. Candidate projects should be included into network topology in a

model for probabilistic analysis, one by one, and their benefits should be estimated. Costs should be estimated using same unit equipment prices. Profitability indices should be calculated for all planning scenarios and average profitability index as a ratio between total sum of profitability indexes for planning scenarios and the number of analyzed planning scenarios should be determined. Prioritization of the projects should be made according to maximum average profitability index. Transmission facility or object with maximum average profitability index should be included into network topology for a studied year, and all calculations have to be repeated in order to find out a candidate project with the second highest average profitability index. This procedure shall be repeated until there are no other candidate projects with the profitability index larger than 1 in any planning scenario.

Transmission system planning process consists of different mutually dependent analyses (technical and economical ones), so it is necessary to define the planning procedure that will be respected during planning process. Following steps in the planning procedure are suggested:

1. Collection of planning data (technical and economical ones);
2. Preparation of the list of candidate projects by the SEE TSOs for planning time horizon;
3. Definition of the planning scenarios;
4. Network modeling (for technical and economical analyses);
5. Identification of network constraints (load flow and security analysis);
6. Evaluation of candidate projects according to technical criteria;
7. Identification of the reviewed list of candidate projects;
8. Prioritization of candidate projects according to technical criteria;
9. Probabilistic analysis;
10. Prioritization of the candidate projects according to economic criteria;
11. Determination of the final network configuration in observed time horizon; and
12. Other technical analyses (short-circuit, stability, voltage).

Proposed SEE transmission system planning procedure is presented in Figure 3 (Chapter 7.6).

Conclusions

In the course of the work on this Study we became aware of the following:

- Planning criteria used by the SEE TSOs today are generally similar and mainly concentrated around the (n-1) security criterion;
- Market oriented transmission investments and investments from regional perspective are not mentioned and satisfactorily treated in the national grid codes;
- National transmission networks are mainly planned according to technical considerations and economic rationalization of new investments generally stays out of interest;
- Methods used by transmission planners are based on deterministic approach and probabilities of different events (network failures, generator dispatch, branches availability

etc.) are not treated satisfactorily which does not allow better economical considerations of network development and inclusion of economic criteria into decision making process;

- The SEE transmission system planning process has to include different uncertainties which will occur in an open electricity market environment. The most important ones are generation investment plan(s) with size and locations of new generators, generators bidding behavior in the future, hydrological conditions, branches and generators future availability, load growth and regional power balance. This study suggested multi-scenario approach in dealing with uncertainties and transmission planning procedure is adjusted to that;
- Transmission development in the SEE may be more effective and faster if following requests are to be fulfilled: a) full independency of Transmission System Operators from production and supply companies; b) acceleration of national authorization procedures for transmission facilities construction; c) effective market design and stable regulatory framework; d) introduction of market oriented signals for transmission investments; e) attraction of private investments into transmission development; f) coordination and full cooperation between the SEE TSOs in planning issues; and g) establishment of a stable financing mechanism that will support regionally important projects;
- Because of a large number of the TSOs over relatively small territory in the SEE, which would be hard to coordinate and direct their attention to the SEE regional prospective projects, and because their main concern remains within national territories, establishment of an official SEE regional transmission planning group is suggested hereby, which should be supported by the Energy Community, the SEE TSOs, the SEE regulatory authorities and the European Commission. This group should deal with the SEE transmission system planning issues, collection of planning data, establishment of planning scenarios, preparation of common network models for necessary analyses (load flow, dynamic, short-circuit, probabilistic models), performance of analyses, comparison of candidate projects according to pre-defined criteria, prioritization of the investments and publication of reports concerning the SEE transmission system future bottlenecks, prediction of congestions from planning perspective and suggestions for further development.

1. INTRODUCTION

1.1. Background

Transmission network planning has been strongly influenced by the electricity market opening. Role of transmission system in a vertically integrated power supply company was to support economical dispatching of existing and future power plants by satisfying a predefined level of reliability in order to meet consumer's present and future needs. Transmission network development was optimized to meet specific criteria with minimum expenses. Transmission planners were supplied with wide range of necessary data concerning future production, consumption and possible exchanges with neighboring countries. Uncertainties were mainly related to electricity consumption and load growth prediction. Transmission networks were somewhere slightly or significantly over-designed in order to satisfy high level of consumption growth. It is also important to mention that transmission systems were designed to serve national needs, with mostly limited capacity of interconnection lines to neighboring power systems to support limited exchanges of electricity and mutual assistance.

Several facts strongly influence transmission planning process under new conditions. These facts are:

- significant uncertainties which appear in a deregulated environment comparing to those which appear in a non-deregulated (monopolistic) environment,
- lack of input data needed for planning process,
- different transmission development objective functions, depending on the view of market players and participants (producers, traders, suppliers, consumers, regulators, operators),
- certain disproportion between technical, economical, environmental and social requests.

Although transmission planners were also faced to different uncertainties in the past, existing and new uncertainties make transmission planning more difficult. Locations and capacities of new power plants, their bidding behavior, existence of the present ones in the future, consumer's reaction to instantaneous electricity price (price elasticity), unknown directions of electricity and power trading, capacity allocation mechanisms, regulatory aspects etc., are hard to be predicted even for the purpose of short-term planning. Standard deterministic approaches used before are obviously not appropriate in new circumstances. Network development based on deterministic power flow analyses of several typical system conditions can not be sufficient any more. Incorporation of multi-scenario analyses that have been used to include some uncertainties is probably only a temporary step in transmission network planning. Possible scenarios concerning power plants grid connection and dispatch, consumption growth and market transactions have to be carefully defined and coordinated between different parties such as transmission grid owners, system operators, market operators and regulatory authorities. Need to include many different uncertainties in network planning will probably lead to increased usage of probabilistic approach in transmission network planning supported by risk estimation techniques.

The existence of different market players (producers, traders, suppliers) and other market subjects (system operators, regulators), separated ownership and control responsibilities over transmission assets somewhere (TSO vs. ISO model), and separated or unbundled companies (production, transmission, distribution, supply) will probably lead to a lack of data needed for transmission network planning. Confidentiality of some data and a lack of willingness to share them between

different parties additionally stress the problem. One approach is to define necessary data needed for transmission planning that have to be exchanged between market players and transmission planners. Otherwise, transmission planners will be faced with additional uncertainties because they will have to predict some data and their assumptions can be wrong, depending on their knowledge of different aspects of electricity market issues and their ability to predict future market activities that is highly uncertain. This is likely to lead towards under-constructed or over-constructed transmission networks.

Each market player has a different view on transmission adequacy and reliability today. Producer wants to give energy to a network without any limitations and it is not interested in what happens behind his unit transformers or power plant bus-bars. Trader wants to buy wherever it finds energy and to sell it to someone without any restrictions and with minimum transmission and cross-border fees. Supplier wants to buy energy as cheap as possible, while system operator has to support market activities and to keep appropriate level of network adequacy and security at the same time. Regulatory authority has to define that security level and to prepare an infrastructure for market in order to reduce or eliminate market power. Network congestions, today one of the main reasons for economic justification of network investments, may provide advantage for generators located in congested area giving them certain market power. Mathematically expressed, all of them have different target functions related to transmission network adequacy and security. Instead of optimizing the sum, today there is a sum of optimums. Achieving an optimal solution for everybody is impossible, so regulatory authority's obligation is to define a unique target function which has to be met during transmission network planning. In other words, regulatory authorities have to define the task of a transmission network and to define technical and economic criteria that have to be met by system operators and transmission network owners (usually merged in the same company), allowing them to include technically and economically justified investments in transmission fee.

Transmission networks have to fulfill different requests based on technical, economic, environmental and social perceiving. Technical requests are usually hard to meet while satisfying economic ones at the same time. Possible technical and economic solutions are usually restricted by environmental aspects. Social aspects have to be met (consumers have to be supplied) balancing economic considerations in transmission network operation and development. It is clear that optimal solution should represent a combination of socio-economic, technical and environmental requests.

1.2. Transmission network planning criteria

Potential network investments should be overviewed comparing them to predefined technical and economic criteria. Technical criteria are mostly defined either on deterministic or on probabilistic basis.

The most common deterministic criterion is the (n-1) criterion, which prescribes technical requests that have to be met after one network branch or generator goes out of service. This criterion is based on the most restrictive system scenario, no matter of its probability of occurrence. This can lead to relatively high security margin during the planning process. Requests are usually related to branch loadings and voltage profile in a network. Considered criterion could be strengthened observing loss of one generator and one branch (n-g-1), loss of two circuits (n-2) and simultaneous loss of one circuit while maintaining another one (n-1-1). Acceptable range of branch loadings could be defined as permanent maximum and short-term (up to ½ h) permitted overloading during

which system operator could take appropriate actions to decrease critical branch loading (re-dispatching, network sectioning, load reduction etc). Qualitative step forward should be more precise (from planning purposes) definition of maximum permitted branch loadings dependent on air temperature (maximum winter loading and maximum summer loading) and line corridors (urban, rural areas).

Deterministic criteria do not include probabilities of the failures in a network. More precise overview of network reliability could be achieved by using probabilistic planning methods which observe the probability of network failures. The most often used probabilistic criterion in transmission network planning is the loss of load probability (LOLP). Regulatory authority may define the level of acceptable LOLP which transmission network has to meet. Different levels of acceptable number of outages and load reduction duration dependent on different load amounts could also be defined. In order to evaluate candidate network investments, probabilistic simulation of observed power system should be done taking into account annual load duration curves. Similar approaches are expected to become more often used in a deregulated environment especially because different uncertainties can be modeled in probabilistic simulations.

The most commonly used economic criterion in transmission network planning is the positive Net Present Value (NPV). This criterion was used in vertically integrated companies as well, but different definition of investment benefits had to be made after electricity market opening, especially concerning congestion costs. Recognition of costs and benefits and their estimation are crucial while observing economic criterion. Some other economic criteria such as payback period or internal rate of return could also be used.

Crucial question while balancing technical and economic criteria is what if some investment satisfies technical but not economic criteria. Example could be found in a case where the technical (n-1) criterion is not satisfied only for several hours per year during peak load situations. Probability that critical line will go out of service during those several hours per year is pretty small because lines availability are usually very high (99% or more). Consequence of this low probability is a violation of economic criterion because expected line benefit is smaller than total costs. Some system operators are going to accept this violation of the (n-1) criterion because their regulated income can not cover needed investments, while other system operators will invest in grid reinforcement in order to satisfy the (n-1) criterion although this investment can not be economically justified. In these examples the economic criterion may or may not overmaster the technical one. Another example can be found concerning bus-bar failures. Such failures are usually not observed by system operator while planning transmission network, so they are not included in the technical criteria. What if some bus-bar failure with a very low probability causes extremely large costs? System operator will probably invest in a new transmission line that connects load with other bus-bar to avoid large possible expenses of such fault. The economic criterion is now satisfied and the technical one is not. Generally, it seems that economic criteria are becoming dominant in open electricity market environment.

1.3. Regional planning

The SEE TSOs are responsible for network planning within their countries. They develop and prescribe different planning criteria which they apply while planning a network. There is no example where one TSO or some other entity plans a network over wide area that includes responsibilities of several TSOs. Planning criteria applied by different TSOs may be the same or very similar, but responsibility of each TSO remains on its own territory.

In the SEE region the high voltage transmission network is operated and controlled (in some cases even owned) by the SEE TSOs. Area of interest for this Study spreads over territories of Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Macedonia, Montenegro, Romania, Serbia, UNMIK, Slovenia and Turkey. Each of them has its own system operator who is responsible for network reliability and security, as well as operational and planning aspects.



Figure 1 Geographic position of the Contracting Parties to the Energy Community Treaty [1]

Planning of interconnection lines has been mutually coordinated by two neighboring TSOs. Interconnection lines are planned primarily to increase transmission capacities between two countries, without taking into account regional needs. The challenge is to define planning criteria which will be applied not only to interconnection lines but also to internal lines inside an area of the SEE TSOs responsibility, taking into account their regional importance.

1.4. The 8th Athens Forum conclusions

The 8th Athens Forum concluded that transmission investment criteria have to be defined from a regional perspective, and transmission projects have to be prioritized according to those criteria. The aim of that conclusion is to support market activities inside the Energy Community and to remove barriers caused by transmission network for free market trading. The work conducted within this Study is directly related to this conclusion, and attempts to define criteria from a regional perspective, but respecting national requests and interests.

1.5. Scope of Work

According to the conclusions of the 8th Athens Forum, the transmission investment criteria for the SEE region have to be defined in the Study, taking into account regional needs. Transmission projects have to be prioritized lately according to those criteria. The Study should analyze the problem of transmission investments in an open market environment defining the most relevant uncertainties in the SEE region, review past experience in transmission network planning, analyze

transmission planning criteria which have been used by different SEE TSOs, review national grid codes and a draft version of regional grid code, suggest transmission investment criteria from a regional aspect and methodology for project prioritization.

Terms of Reference are presented in Appendix 1. This Study refers to transmission system planning issues (mostly long-term), while operational issues are not its subject.

2. TRANSMISSION NETWORK PLANNING IN AN OPEN ELECTRICITY MARKET

2.1. Transmission planning in the vertically integrated companies

Transmission network planning methods may be divided into several categories according to [2]:

1. Planning uncertainties (deterministic and non-deterministic methods),
2. Planning time horizon (static and dynamic approach), and
3. Planning environment (vertically integrated environment or market environment).

Transmission network planning inside the vertically integrated power companies was mostly performed in order to determine network configuration in the future that would support power plants economic dispatch and satisfy predefined technical requests with minimum construction, operation and maintenance costs. Planning of new generation capacities and transmission network was usually performed together on the basis of load growth predictions. Planning was performed in the same company and input data for transmission planning were not the significant source of uncertainty. Uncertainties of power plants construction and load growth predictions were taken into account usually through sensitivity analysis and multi-scenario analysis. Transmission network planning was performed by simulating power system operation or using mathematical optimization methods such as linear programming, dynamic programming, non-linear programming or mixed integer programming [3].

Static and dynamic simulations of power system operation in the future, with defined generation investment plan and load growth prediction, were performed for typical system operating conditions, and transmission network adequacy and security were estimated according to predefined criteria. This was the most usual way of transmission network planning inside the vertically integrated power companies worldwide.

Optimization methods were used mostly in large areas where costs of transmission facilities construction are very high (like South America). The aim of these methods was to find minimum of target function (usually defined as cost function) with set of restrictions comprising power flows equations. Optimization problem was non-linear which can not be solved by using classical optimization techniques so attention was mainly directed to problem solving methods.

The example is used to present transmission network planning inside the vertically integrated companies, and the latter to point out why well-known techniques are not appropriate in an open market environment. The example is presented in Appendix 2.

Applying this example to the South East Europe (SEE) region in the past, when vertically integrated companies existed, a solution that comprises new line 1-2 construction would be surely chosen and company would invest money for that. Any loss of load was not allowed, even in the situations of peak load, with one line out of operation, with very low probability. Economic considerations were not the main rationale in decision making process. To summarize, transmission network planning within the SEE power supply companies in the past was characterized by the following:

- (n-1) criterion was applied and was dominant in planning,

- only peak load situations were analyzed (minimum load situations were also analyzed somewhere to observe voltage profile),
- probabilistic methods were generally not used, so probability of network failures and overloadings were not observed,
- economic criteria were not dominant in decision making process,
- uncertainties in input data (production plan, generators dispatch, load growth, etc.) and related risk of wrong investments were not treated satisfactory.

2.2. Transmission planning in a market environment

As one may notice from the example presented in Appendix 2, there are significant uncertainties in an open market environment, which have to be taken into account during transmission system planning. The most significant uncertainties are:

- power plants construction,
- power plants decommission,
- generators engagement (bidding behavior),
- load growth predictions,
- demand elasticity,
- market prices,
- market transactions,
- bilateral contracts,
- regulatory aspects,
- market organization, etc.

There are some important issues which have to be considered concerning transmission system planning in an open market environment:

- network planning has to include the most important uncertainties in the future,
- traditional mathematical optimization methods and deterministic models are not appropriate for market conditions without significant improvements,
- each network investment decision include some risk, so risk analysis techniques should be applied in network planning,
- investment decisions depend on applied planning criteria that should be defined according to a strategic view on transmission role in a market (economically optimal or satisfactorily secure network, allowance of full competition no matter of development costs etc.),
- having in mind the necessity for inclusion of uncertainties in planning process, risk analysis and economic calculations, the probabilistic planning methods have advantages comparing to deterministic ones,
- network development in an open market conditions should be initiated by market oriented signals such as location marginal pricing or congestion costs.

Observing all previously noted, it may be concluded that the SEE TSOs still plan their networks as before, without taking into consideration future market conditions. The technical (n-1) criterion is still the main rationale for network strengthening, economic criteria have not been applied, deterministic methods have been dominantly used, almost neither of them use probabilistic methods (except Romania), uncertainties have not been included into planning process, there are not enough, or not at all, market signals which may lead to network investments.

3. EXISTING PLANNING CRITERIA

This summary of transmission network planning criteria applied by different TSOs in the SEE region is based on the Questionnaire that was filled by SECI members (representatives of the SEE TSOs responsible for network planning issues) during December 2006. The structure of the Questionnaire and answers are shown in detail in Appendix 3.

3.1. Albania

Albanian TSO (until recently organized inside vertically integrated company KESH, but prepared to be unbundled even in ownership terms) is responsible for transmission planning, and it has to prepare short, mid and long term plans of transmission development. Network development plans have to be approved by regulatory authority. Transmission investments in Albania are financed through transmission fee and loans. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, thermal overloadings of branches, voltage declination below permitted range, loss of stability, loss of load and interruption of power transits must not appear.

TSO uses different line loading limits for winter and summer period, but does not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not valueate the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes load flow, security analysis and short-circuit calculations are conducted.

TSO values possible investments according to economic criterion. Profitability indices, such as the ratio between benefits and costs, of some investment is used. The following types of benefit are estimated:

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs.

Undelivered electricity costs in Albania have been estimated to 0.5 €/kWh.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- branches availability,

- market transactions,
- country power balance.

Risk estimation is conducted by using sensitivity analysis.

3.2. Bosnia and Herzegovina

In Bosnia and Herzegovina, the Elektroprenos-Elektroprijenos BiH (transmission company – the grid owner) is responsible for transmission network planning, the NOS BiH (Independent System Operator) for revision and the State Electricity Regulatory Agency (DERK - SERC) for approval of these plans. They have to prepare short (one year) and long term (10 years) transmission development plans. Transmission investments in Bosnia and Herzegovina are financed through transmission fee and loans. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination below permitted range, loss of stability, loss of load, interruption of power transits and disturbance spreading over power system must not appear.

Transmission company and system operator do not use different line loading limits for winter and summer period, and do not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. Transmission company and system operator do not value the probability of (n-1) events, and do not use any other technical criterion in network planning. For the planning purposes, the load flow, security analysis, short-circuit and stability calculations are conducted.

Transmission company and system operator value possible investments according to economic criterion but this criterion has not been clearly defined. Only reduction of losses costs is included in economic function.

Undelivered electricity costs in Bosnia and Herzegovina have not been defined.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- existing power plants decommissioning,
- country power balance.

Transmission company and system operator do not conduct risk estimations.

3.3. Bulgaria

Bulgarian TSO (NEK EAD - organized as independent state owned company but includes hydro production and supply) is responsible for transmission planning, and it has to prepare short and mid term plans of transmission development. Network development plans have to be approved by the regulatory authority. Transmission investments in Bulgaria are financed through transmission fee and loans. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line or transformer. With one branch out of operation, the thermal overloadings of branches, voltage declination below permitted range, loss of stability, loss of load and interruption of power transits must not appear.

TSO does not use different line loading limits for winter and summer period, and does not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes, the load flow, optimal load flow, security analysis, short-circuit and dynamic calculations are conducted.

TSO does not value possible investments according to economic criterion.

Undelivered electricity costs in Bulgaria have been estimated to 2 €/kWh.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- branches availability,
- market transactions,
- country power balance.

TSO does not conduct risk estimations.

3.4. Croatia

Croatian TSO (HEP OPS - organized inside vertically integrated company HEP Group, with leased transmission assets from the holding) is responsible for transmission planning, and it has to prepare short term transmission development plans (3 years). Network development plans have to be approved by the regulatory authority. Transmission investments in Croatia are financed through transmission fee and loans. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer and generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination out of permitted range, loss of stability, loss of load, interruption of power transits and disturbance spreading over power system must not appear.

TSO does not use different line loading limits for winter and summer period, and does not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes load flow and security analysis are conducted.

TSO values possible investments according to economic criterion, although specific economic criterion has not been defined by the grid code or any other document. Some planning studies for Croatian TSO were prepared by using a profitability index as a ratio between benefits and costs of network investments. Economic function in those studies included loss of load costs, re-dispatching costs and costs of losses.

Undelivered electricity costs in Croatia have been estimated to 2.56 €/kWh.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario and probabilistic analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- branches availability,
- market transactions,
- country power balance.

Uncertainties are taken into account through different planning scenarios. Uncertainties in branches availability are taken into account by using probabilistic method while applying economic planning criterion.

TSO does not conduct risk estimations.

3.5. Macedonia

In Macedonia TSO (MEPSO – fully independent from the production and supply companies including ownership unbundling) is responsible for transmission network planning. Regulatory authority has to approve investment plans. TSO has to prepare short, mid and long term plans of transmission development. According to the Energy Law, TSO prepares 5 year development program (transmission investment plans) and gives them for the approval to the Energy Regulatory Commission. According to the grid code, TSO prepares the System Reliability Study for next 10 years and gives it for approval to the Energy Regulatory Commission.

Transmission investments in Macedonia are financed through transmission fee and loans. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination out of permitted range, loss of stability, loss of load and interruption of power transits must not happen. Cascade switching of elements is also not acceptable.

TSO does not use different line loading limits for winter and summer period but it allows short-term overloading above permitted limits according to the protection settings. 400 kV OHL has over-current protection relays with 2 step settings:

$$\begin{aligned} 1^{\text{st}} \text{ STEP: } & I \geq 1760 \text{ A, } 1218 \text{ MVA, } t = 1200 \text{ sec. trip} \\ 2^{\text{nd}} \text{ STEP: } & I \geq 2080 \text{ A, } 1440 \text{ MVA, } t = 20 \text{ sec. trip} \end{aligned}$$

Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes, the load flow, security analysis, short-circuit and stability calculations are conducted.

TSO values possible investments according to economic criterion. When solving specific problems during planning phase, from set of technically acceptable options, solution is selected by applying economic criterion (the NPV method). In feasibility studies for investigating new interconnection projects, comprehensive cost-benefit analyses are performed. Reduction of cost of losses and benefit from telecommunication lines are estimated. While investigating solutions for local (internal) problems, simple NPV method is applied, taking into account reduction in active power losses and difference in operational and maintenance costs.

Undelivered electricity costs in Macedonia have been estimated to less than 1 €/kWh.

Different criteria for interconnection lines are applied. In recent feasibility investigations of new interconnections, the SDDP software was used, that gives overall change in system operational costs derived by different interconnection options and different working regimes of power systems (isolated or coordinated operation and development).

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- country power balance.

TSO does not perform risk estimations.

3.6. Montenegro

TSO from Montenegro (organized inside vertically integrated company EPCG; functional unbundling formally accomplished – legal unbundling in preparation; recently obtained three operational licences – transmission, system operation and market operation) is responsible for transmission planning, and it has to prepare short and mid term plans of transmission development which have to be approved by the regulatory authority. Transmission investments in Montenegro are financed through loans. In future transmission investments will be financed through transmission fee which yet needs to be approved by the regulatory authority. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer and generator. With one branch or generator out of operation, the thermal overloadings of branches, loss of stability, loss of load and interruption of power transits must not appear.

TSO uses different line loading limits for winter and summer period, and allows short-term overloading above permitted limits. During interrupted operational conditions overloading of elements above thermal ratings is allowed for 20 minutes according to their specifications. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events. TSO also uses (n-2) criterion in network planning. For the planning purposes, the load flow, security analysis and short-circuit calculations are conducted.

TSO does not value possible investments according to economic criterion.

Undelivered electricity costs in Montenegro have been estimated to less than 1 €/kWh.

Different criteria for interconnection lines are not applied. Interconnection lines are planned on regional level.

The most important uncertainty in the future that is taken into account during transmission network planning through multi-scenario analysis is the uncertainty in hydrological conditions.

TSO does not conduct risk estimations but in the future the regulatory authority will assess a risk of incorrect transmission investments.

3.7. Romania

Romanian TSO (Transelectrica – fully independent from the production and supply companies, including ownership unbundling) is responsible for transmission planning and it has to prepare long term plans of transmission development. TSO has to prepare a transmission development plan for 10 years. These plans are updated every 2 years. Network development plans have to be approved by the regulatory authority. Transmission investments in Romania are financed through transmission fee and loans. Grid code defines planning criteria. Additional to the grid code there is a standard with several procedural and technical details: PE026/1995 - Standard for the Romanian power system design.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings

of branches, voltage declination out of permitted range, loss of stability, loss of load and interruption of power transits must not appear. Tripping of the other installations through the protective devices of the equipment which are not directly affected by the disturbance also has to be avoided.

TSO does not use different line loading limits for winter and summer period, and does not allow short-term overloading above permitted limits. Different thermal ratings are used only for operational purposes. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, but in the long term plans the reliability indicators are assumed for each substation. TSO uses other technical criteria in network planning:

- (n-2) criterion (used to design transmission capacity for the nuclear power plant),
- static and dynamic stability,
- technical criteria to design the reactive power compensation installations.

For the planning purposes, the load flow, security analysis, probabilistic analysis, short-circuit and dynamic calculations are conducted.

TSO values possible investments according to economic criterion. The efficiency of the short and medium term investments in transmission network has to be justified in the planning stage by using at least the payback time criteria. The transmission network long-run planning studies (10 years) have to offer hierarchical development solutions based on economic criteria. Economic function includes:

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines, and any other benefits.

Undelivered electricity costs in Romania have been estimated to 0.8 €/kWh.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- existing power plants decommissioning,
- load prediction,
- branches availability,

- regulatory and market issues,
- market transactions,
- country power balance.

TSO does not conduct risk estimations.

3.8. Serbia

Serbian TSO (EMS - fully independent from the production and supply companies, including ownership unbundling) is responsible for transmission planning and it has to prepare one year and five years plans and provide it to the regulatory authority for approval. Transmission investments in Serbia are financed through transmission fee and loans. It is expected that the grid code will define planning criteria once the regulatory authority approves it (expected by July 2007).

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination below permitted range, loss of stability, loss of load, interruption of power transits and disturbance spreading over power system must not appear.

TSO uses different line loading limits for winter and summer period because there are different tunings of over-current protection during winter and summer period. TSO does not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events. For the planning purposes, the load flow, security analysis and short-circuit calculations are conducted.

TSO values possible investments according to economic criterion. Profitability index such as the ratio between benefits and costs of some investments is used. Economic function includes:

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of congestion costs,
- benefit from telecommunication lines.

Reduction of congestion costs has been used when planning interconnection lines.

Undelivered electricity costs in Serbia have been estimated between 1 €/kWh and 3 €/kWh (exact value has not been defined).

TSO uses different criteria for interconnection lines based on the difference in energy prices.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis and probabilistic calculations, are:

- new power plants size and location,
- generators engagement,

- hydrological conditions,
- market transactions,
- country power balance.

TSO does not conduct risk estimations.

3.9. UNMIK

UNMIK TSO (KOSTT - fully independent from the production and supply companies, including ownership unbundling) is responsible for transmission planning, and it has to prepare short, mid and long term plans of transmission development. Network development plans have to be approved by the regulatory authority. Transmission investments in UNMIK are financed through transmission fee and loans. Grid code will define planning criteria (approved by the regulatory authority and awaits full implementation by the TSO).

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination out of permitted range, loss of stability, loss of load and interruption of power transits must not appear.

TSO uses different line loading limits for winter and summer period, but does not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes, the load flow, security analysis, optimum load flow and short-circuit calculations are conducted.

TSO values possible investments according to economic criterion. Profitability index such as the ratio between benefits and costs of some investments is used. Following types of benefit are estimated:

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs.

Undelivered electricity costs in UNMIK have been estimated to 0.4 €/kWh.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,

- existing power plants decommissioning,
- branches availability,
- market transactions,
- country power balance.

Risk estimation is conducted by using sensitivity analysis.

3.10. Slovenia

Slovenian TSO (ELES – separated from production and supply companies) is responsible for transmission planning, and it has to prepare short and mid term plans of transmission development. Network development plans have to be approved by the regulatory authority. Transmission investments in Slovenia are financed through transmission fee and loans. Grid code defines planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination below permitted range, loss of stability, loss of load and interruption of power transits must not appear.

TSO does not use different line loading limits for winter and summer period, but it allows short-term overloading above permitted limits. During interrupted operational conditions, the overloading of elements above thermal rating is allowed for 20 minutes according to their specifications. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes load flow, security analysis and short-circuit calculations are conducted.

TSO does not use any economic criterion in network planning.

Undelivered electricity costs in Slovenia have been estimated between 1 €/kWh and 3 €/kWh.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning through multi-scenario and probabilistic analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- load prediction,
- market transactions,
- country power balance.

Risk estimation has not been conducted.

3.11. Turkey

Turkish TSO (organized inside vertically integrated company TEIAS) is responsible for transmission planning, and it has to prepare short, mid and long term plans of transmission development. Under the law TSO is the owner of the HV and EHV network and also responsible for planning construction, operation and maintenance of transmission system. Therefore TEIAS prepares the “Transmission System Investment Plan” and additionally the “Ten Years Statement Report” for the development of the transmission system in ten years period. Network development plans have to be approved by the regulatory authority. The “Ten Years Statement Report” is submitted to the regulatory authority which makes the final proposal. Transmission investments in Turkey are financed through transmission fee, loans, internal TSO financial sources and by private investors. Grid code and “System Security and the Quality of Supply Document” define planning criteria.

The main criterion for network planning is the (n-1) criterion, related to the loss of single line, transformer or generator. With one branch or generator out of operation, the thermal overloadings of branches, voltage declination out of permitted range, loss of stability, loss of load and interruption of power transits must not appear.

TSO uses different line loading limits for winter and summer period. During winter period thermal rating for 25° is used, for summer and minimum (spring) period thermal ratio for 40° is used (details are given in the “System Security and the Quality of Supply Document”). TSO does not allow short-term overloading above permitted limits. Voltage limits in 400 kV, 220 kV and 110 kV network are shown in Appendix 3. TSO does not value the probability of (n-1) events, and does not use any other technical criterion in network planning. For the planning purposes, the load flow, security analysis, optimum load flow, short-circuit and stability calculations are conducted.

TSO does not value possible investments according to economical criterion. Undelivered electricity costs in Turkey have not been estimated.

Different criteria for interconnection lines are not applied.

The most important uncertainties in the future, which are taken into account during transmission network planning using multi-scenario analysis, are:

- new power plants size and location,
- generators engagement,
- hydrological conditions,
- existing power plants decommissioning,
- load prediction,
- branches availability,
- regulatory and market issues,
- market transactions,
- country power balance.

Risk estimations have not been conducted in Turkey.

3.12. Summary of existing planning criteria used by the SEE Transmission System Operators

Based on the questionnaire that was given to eleven SEE Transmission System Operators (Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Macedonia, Montenegro, Romania, Serbia, UNMIK, Slovenia and Turkey) about transmission network planning issues, it can be concluded that:

- SEE TSOs are responsible for transmission network planning, and development plans have to be approved by national regulatory authorities everywhere;
- SEE TSOs are obliged by national laws to prepare transmission development plans up to 20 years ahead. The most often time horizons for planning are 1 year ahead and five years ahead;
- Transmission investments are mostly financed through transmission fees and loans. Only Turkey allows private investors to construct transmission facilities;
- Transmission planning criteria are published in national grid codes;
- The main technical criterion for transmission system development is the (n-1) security criterion, which is applied everywhere. It is mostly related to the loss of single line, transformer or generator, when following events are not permitted:
 - thermal overloadings of branches,
 - voltage declination below permitted range,
 - loss of stability,
 - loss of load,
 - interruption of power transits, and
 - disturbance spreading over power system;
- The (n-2) criterion is used only in Montenegro and Romania (in Romania only for grid connection of the nuclear power plant);
- Other technical criteria for transmission system planning are not used, except in Romania where stability criteria and compensation facilities installation criteria are prescribed;
- SEE TSOs usually do not define different thermal ratings for winter and summer operational circumstances, or for normal and emergency conditions. Different ratings are defined somewhere (Albania, Montenegro, Serbia, Turkey, UNMIK) for winter and summer operation with respect to the outside temperature, and different ratings are defined somewhere for normal and emergency conditions with respect to the protection systems settings (Macedonia, Montenegro, Slovenia);
- There are no TSOs in the SEE region which evaluates the probability of (n-1) events during transmission system planning;
- SEE TSOs usually conduct load flow computations, security analysis and short circuit calculations during planning process. Optimal power flows (Bulgaria, Turkey, UNMIK) and stability analysis (B&H, Bulgaria, Macedonia, Romania, Turkey) are also conducted somewhere ;
- Probabilistic analyses during transmission system planning process are performed only in Romania;

- Economic criteria in transmission network planning are applied somewhere (Albania, B&H, Croatia, Macedonia, Romania, Serbia, UNMIK);
- The mostly used economic criterion is the profitability index as the ratio between benefits and costs of transmission investments;
- SEE TSOs who apply economical criterion usually estimate reduction of the cost of losses, loss of load costs, re-dispatching costs, congestion costs and benefit from telecommunication lines (Table 2);
- Undelivered electricity costs across the SEE region are lower than 3 €/kWh (Table 3). The lowest value is applied for planning purposes in UNMIK (0.4 €/kWh), and the highest value is applied in Croatia (2.56 €/kWh). Some countries have not defined those costs;
- Generally, additional planning criteria are not applied for interconnection lines. Some countries apply different planning criteria based on the system operational costs (Macedonia) and difference between energy prices (Serbia);
- Uncertainties are mostly taken into account using multi-scenario analysis (Table 4). The most important uncertainties are:
 - new power plants size and location,
 - generators engagement,
 - hydrological conditions,
 - market transactions,
 - country power balance.
- Risk assessments are not conducted by the SEE TSOs.

Benchmarking table about transmission system planning issues among the SEE TSOs is presented below.

Table 1 Transmission system planning issues among the SEE TSOs

| Transmission system planning issue | Albania | B&H | Bulgaria | Croatia | Macedonia | Montenegro | Romania | Serbia | UNMIK | Slovenia | Turkey |
|--|----------------------------|--------------------|-----------------------|---------------------------|--|------------------|-------------------------------|-----------------------------------|----------------------------|--------------------|---|
| Responsibility for transmission system planning | TSO | TSO | TSO | TSO | TSO | TSO | TSO | TSO | TSO | TSO | TSO |
| Planning horizon * | ST/MT/LT | ST/LT | ST/MT | ST | ST/MT/LT | ST/MT | LT | ST/MT | ST/MT/LT | ST/MT | ST/MT/LT |
| Approval from regulatory authority | YES | YES | YES | YES | YES | YES | YES | YES | YES | YES | YES |
| Financing of transmission investments | Trans. fee / loans | Trans. fee / loans | Trans. fee / loans | Trans. fee / loans | Trans. fee / loans | loans | Trans. fee / loans | Trans. fee / loans | Trans. fee / loans | Trans. fee / loans | Trans. fee / loans / internal sources / private |
| Definition of planning criteria | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code | YES Grid Code |
| Usage of (n-1) criterion | YES | YES | YES | YES | YES | YES | YES | YES | YES | YES | YES |
| Different thermal ratings for winter and summer regime | YES | NO | NO | NO | NO | YES | NO | YES | YES | NO | YES |
| Different thermal ratings for normal and emergency operation | NO | NO | NO | NO | YES | YES | NO | NO | NO | YES | NO |
| Valuation of the probability of (n-1) events | NO | NO | NO | NO | NO | NO | NO | NO | NO | NO | NO |
| Other technical criteria | NO | NO | NO | NO | NO | YES (n-2) | YES (stability, compensation) | NO | NO | NO | NO |
| Analyses during planning process** | LF-SA / SC | LF-SA / SC / SS | LF-SA / OPF / SC / SS | LF-SA | LF-SA / SC / SS | LF-SA / SC | LF-SA / PA / SC / SS / EA | LF-SA / SC | LF-SA / OPF / SC | LF-SA / SC | LF-SA / OPF / SC / SS |
| Application of economical criteria | YES (profitability index) | YES | NO | YES (profitability index) | YES (Net Present Value) | NO | YES (payback period) | YES (profitability index) | YES (profitability index) | NO | NO |
| Additional planning criteria for interconnection lines | NO | NO | NO | NO | YES (change in system operational costs) | NO | NO | YES (difference in energy prices) | NO | NO | NO |
| Risk analysis techniques | YES (sensitivity analyses) | NO | NO | NO | NO | NO | NO | NO | YES (sensitivity analyses) | NO | NO |

* ST: short-term; MT: mid-term; LT: long term

** LF-SA: load flow and security analysis; OPF: optimum power flows; PA: probabilistic analysis; SC: short-circuit analysis; SS: stability simulations; EA: economic analysis

Table 2 Types of benefits from transmission investments which are estimated by the SEE TSOs who apply economical criterion in transmission system planning

| Benefit | Albania | B&H | Croatia | Macedonia | Romania | Serbia | UNMIK |
|---------------------------------|---------|-----|---------|-----------|---------|--------|-------|
| Reduction of the cost of losses | √ | √ | √ | √ | √ | √ | √ |
| Loss of load costs | √ | | √ | | √ | √ | √ |
| Re-dispatching costs | √ | | √ | | √ | | √ |
| Congestion costs | √ | | | | √ | √ | √ |
| Telecommunication lines | | | | √ | √ | √ | |
| Other | | | | | √ | | |

Table 3 Undelivered electricity costs (loss of load costs) in SEE

| Country | <1 €/kWh | 1 €/kWh <LoLC<3 €/kWh | >3 €/kWh |
|------------------------|---------------|-----------------------|----------|
| Albania | √ (0,5 €/kWh) | | |
| Bosnia and Herzegovina | | | |
| Bulgaria | | √ (2 €/kWh) | |
| Croatia | | √ (2,56 €/kWh) | |
| Macedonia | √ | | |
| Montenegro | √ (0 €/kWh) | | |
| Romania | √ (0,8 €/kWh) | | |
| Serbia | | √ | |
| Slovenia | | √ | |
| Turkey | | | |
| UNMIK | √ (0,4 €/kWh) | | |

Table 4 The most important uncertainties in transmission system planning

| Country | New power plants size & location | Generators engagement | Hydrological conditions | Existing power plants decommission | Load prediction | Branches availability | Regulatory and market issues | Market transactions | Country power balance |
|------------------------|----------------------------------|-----------------------|-------------------------|------------------------------------|-----------------|-----------------------|------------------------------|---------------------|-----------------------|
| Albania | √ | √ | √ | | | √ | | √ | √ |
| Bosnia and Herzegovina | √ | √ | √ | √ | | | | | √ |
| Bulgaria | √ | √ | √ | | | √ | | √ | √ |
| Croatia | √ | √ | √ | | | √ | | √ | √ |
| Macedonia | √ | √ | √ | | | | | | √ |
| Montenegro | | | √ | | | | | | |
| Romania | √ | √ | √ | √ | √ | √ | √ | √ | √ |
| Serbia | √ | √ | √ | | | | | √ | √ |
| Slovenia | √ | √ | √ | | √ | | | √ | √ |
| Turkey | √ | √ | √ | √ | √ | √ | √ | √ | √ |
| UNMIK | √ | √ | √ | √ | | √ | | √ | √ |

4. GRID CODES REVIEW

This section describes planning standards and planning criteria which are defined in the national grid codes across the SEE region. They are mostly available on internet [4-13]. Review of the same topic is provided for the draft version of the Regional Grid Code, prepared by EdF [14]. Transmission system planning issues are differently treated in national grid codes, described with different details concerning the topic, so their description may vary from more to less detailed in the Chapter that follows.

4.1. National grid codes

4.1.1. Albania

Planning standards, procedures and criteria are published in the Albanian “Transmission System Code – Part II: Planning Code” [4].

The planning code specifies the criteria and procedures to be applied by the OST sh.a. (transmission system operator which unbundling is yet to be completed in ownership terms) in order to plan and develop the Transmission System. The objectives of the planning code are to:

- establish procedures of information exchange between OST sh.a. and customers respecting any customer proposal on the development of their systems/objects that may affect the transmission system behavior;
- detail the information that OST sh.a. shall make available to customers in order to facilitate the identification and evaluation of possibilities for use or connection to the transmission system;
- detail the information that OST sh.a. requires from customers in order to plan the development of the transmission system and assist customers proposed developments;
- specify planning and design standards and procedures that shall be applied by OST sh.a. for transmission system planning and development.

OST sh.a. has to prepare the prospective plan that covers forecasts on demand, peak load, additional electric capacity, transmitting capacity, losses and other important parameters of the power system for the time horizon of 15 years. The prospective plan is the basis for transmission system planning and development.

Transmission system perspective plan has to be based on studies on power flows, studies on short-circuits, studies on static and dynamic stability and studies on non-supplied power. Data needed for transmission system planning are specified in the document.

In the section related to the transmission system planning criteria, the following objective is defined: “the transmission system shall be planned to operate reliably and safe, and efficiently for all consumers in order to guarantee uninterrupted electricity supply with acceptable levels of voltage and frequency according to criteria described by the Code”.

For the transmission system planning the (n-1) criterion is applied. It is applied for regimes with programmed maximal loads. For 400 kV and 220 kV lines the (n-1) criterion is used to define the

conductor section of transmission system lines for the current passing in each line of the system referring to a basic operating regime that assumes the un-planning of breakdowns of main generating plants. For 110 kV lines the (n-1) criterion is applied for closing of all 110 kV rings and switching on all 110 kV lines that work in parallel with 400 kV and 220 kV lines.

The technical criteria to verify the static and dynamic stability of the transmission system performance takes into consideration maximal load regimes, 5 year verification period and a list of simulations prepared based on experience.

Establishing of installation for reactive power generation/absorption is performed by analyzing the voltage levels in all nodes and in all operation regimes with (n) and (n-1) configuration. Voltage limits are set to:

- 400 kV network (360 – 420 kV),
- 220 kV network (198 – 242 kV),
- 110 kV network (99 – 123 kV).

Following criteria of transmission designing are defined:

- Transmission system lines should possibly be designed as two circuit lines;
- For one circuit existing line, the possibility of another circuit should be considered;
- The selected line track way should be as optimal as possible regarding the passing territory;
- Designing and construction of lines should be according to International Standards and effective Legislation.

Transmission system planning is performed through load flow computations, short-circuit and stability studies that have to be performed under the following regimes:

- The system shall be planned to maintain the voltage and eliminate overload for (n) and (n-1) criteria. The (n-1) criterion shall be applied to switching off generating units, transformers or transmission lines;
- The peak load shall be covered on two occasions: minimal thermal plants generation and minimal hydro plants generation;
- The optimum of transmission system reactive compensation shall be established by studies identifying and metering the current in lines and loads under transformation, in order to define voltage levels during the peak load. Capacitors should be of the regulated type to avoid voltage over increase;
- The automatic (relay) protection shall correspond to the following time periods of short connection switching off: 80 ms for 400 kV, 110 ms for 220 kV and 120 ms for 110 kV elements;
- Studies are performed on the stability from temporary overload in 400 kV, 220 kV and 110 kV lines to assure that the frequency and the wave of overload should not exceed the allowed values of isolation of the main equipment and protecting equipment.

4.1.2. Bosnia and Herzegovina

Grid code was prepared by NOS BiH (Bosnian Independent System Operator) and approved by SERC (Bosnian State Electricity Regulatory Commission) in July 2006 [5]. The grid code defines the manner of planning and development of the transmission system, conditions for connection (procedures, contracts, criteria), the manner of operational planning (consumption forecast, parties responsible for balancing, management of grid limitations), and operational activities (dispatching, procedures, communications), measures in extraordinary situations (consumption control, restart of the system after black-out), the manner of billing metering in the power system and other necessary technical measures for qualitative and reliable operation of the transmission system.

The following planning criteria have been defined in the grid code:

- planned transmission network has to be designed to allow contracted and planned electricity transmission, reliable power system control and management, and economical supply of electricity, according to the UCTE Policy 3;
- planned configuration has to be based on economic criteria;
- transmission network has to be designed according to the (n-1) criterion;
- transmission network has to be planned in such a way that static and transient stability are not jeopardized, as well as voltage profile.

Procedures of cooperation between the Transmission System Company and the Independent System Operator are defined in the Grid Code. The ISO is obliged to prepare generation indicative plan for 10 years period to inform the users about the needs and projects of construction of new generation capacities. Transmission system shall be planned taking into account this generation indicative plan.

B&H Grid Code also defines in detail input data for planning purposes that shall be submitted to the institutions responsible for planning.

4.1.3. Bulgaria

Bulgarian Grid Code [6] prescribes transmission system general provisions, defines objectives and scope of planning, planning procedure, and information provision and interchange for planning purposes.

Transmission service provider shall develop and present a five-year plan of transmission system development that shall be updated every year. The plan shall indicate those points of the power grid that are best suited for construction of new connections for future power transmission with a view to promote competition and development of the transmission system.

The plan shall contain information about the operating parameters of the transmission system: transmission capacity by main directions, power flows at maximum load on the power system, load in the points of connection of the transmission system users, levels of short-circuit currents in 750 kV, 400 kV, 220 kV and 110 kV buses of the substations, transmission and transformation losses of power and energy in the power grid under maximum load upon the power system, suggestions for transmission system development and/or changes of topology, scheduled power interchanges with external (foreign) partners and proposals for construction of new interconnection power lines.

Transmission system shall meet in the process of operation in a normal operating mode the (n-1) criterion which means that:

- Disconnection of any power grid component (power line, transformer unit, generation set or compensating device) as well as any component group of the power grid (busbars in a high-voltage switchgear, etc.) that can be simultaneously switched off by the action of a single protection device or by the action of several protection devices as a result of one single-mode failure, should not result in:
 - interruption of supply to electricity consumers,
 - overload of the power grid components remaining in operation,
 - deterioration of electricity supply quality,
 - reduction of the stability margin,
 - disruptions in the operating mode of neighboring power systems in parallel to which the Bulgarian PS operates.
- Disconnection of a double power line laid on a common line of poles is considered as a single-mode event;
- The (n-2) reliability criterion shall be applied upon connection of a nuclear power plant to the transmission system.

The grid code also defines that reporting on the reliability criteria shall be done on the basis of a comparative engineering economic analysis of the following factors:

1. probability of a certain type of accident;
2. consequences of such type of accident;
3. costs required to cover the permanent risk; and
4. cost of the protection measures against development of the accident.

4.1.4. Croatia

Croatian Grid Code [7] defines objectives and scope of transmission system planning, planning criteria and stability requests.

TSO (HEP-OPS) shall perform following tasks in transmission system planning:

- Transmission system shall be planned and designed to transmit contracted or predicted energy flows, to allow reliable system operation and control and to assure economical supply with voltages that are within quality range;
- Transmission system shall be designed according to the (n-1) criterion;
- Transmission system shall be planned taking into account existing loadings and power plants production, requests of distribution networks and consumers requests that are connected or will be connected to the grid in short, mid and long term period;
- Transmission system shall be developed using solutions that fulfill technical criteria with minimum costs.

The (n-1) criteria is applied to 400 kV, 220 kV and 110 kV network, and it is related to the single loss of one line, cable, transformer, interconnection line or generator when following events have to be avoided:

- permanent disturbance of ratings (voltage, frequency, current) that jeopardize system operation or cause equipment malfunction;
- changes or interruption of long-term contracted electricity exports;
- loss of load; and
- tripping of remote elements that are not directly influenced by failures.

The (n-1) criterion is not applied on both circuits of double circuit lines. The (n-2) criterion may be observed to analyze unavailability of two network branches because of planned and random outages. The (n-1) criterion is fulfilled if unwanted consequences are avoided by re-dispatching of generators.

4.1.5. Macedonia

Transmission network planning criteria are defined in Part II – Planning Conditions of Macedonian Grid Code [8]. Grid Code specifies that during planning process the system's adequacy is dimensioned according to the generally accepted (n-1) criterion saying that the outage of any element must not jeopardize system operation safety because of the limited values which are reached or surpassed in regards to electricity, voltage, stability etc. When analyzing the (n-1) criterion it is compulsory to define the list of most probable incidental outages along with the respectively available corrective measures. Outage of several elements, the (n-k) criterion, should be inspected in case of large probability of endangering the system security. Less probable outages, such as busbar outage or circuit breaker defect do not have to be included in the planning. The risk of busbar outage with undelivered power up to 200 MW is accepted.

It is necessary that short circuit current at any node of the system during normal operation does not surpass the switching power of the installed devices at the node.

Macedonian TSO (MEPSO) is obliged to prepare Power System Reliability Study for 10 years period that should be based on forecasted electricity and power demand, assessment of production adequacy, assessment of transmission adequacy and assessment of interconnection necessity with other power systems. This Study should imply measures that will meet the requirements of future electricity demand and maintain the quality in accordance to the UCTE reliability standards, while maintaining least cost of transmission network development.

Grid code defines that transmission system development plans have to be established upon various exchanges and power injections scenarios according to the regional electricity market, and based on sensitivity analysis, taking into account hydrological situations, market price fluctuations, etc.

4.1.6. Montenegro

Montenegrin Grid Code [9] includes the Planning Code that prescribes planning procedure and planning standards, as well as planning data requirements.

Transmission network planning and development are based on the system user's requests and necessity for new transmission capacities, caused by:

- load growth,
- new power plants, direct consumers or distribution systems connections to the grid,
- change in power flows caused by different reasons,
- request for security and quality increasing, and
- any combination of above mentioned reasons.

Development of transmission system includes:

- new transmission element construction,
- strengthening of existing transmission elements (reconstruction and capacity increase),
- protection systems tuning and their modernization,
- network topology change,
- constant monitoring and new technological solutions adoption.

Transmission Company and Transmission System Operator prepare network development plans, concerning short-time (1 year) and mid-time frame (5 years). Development plans are based on the planning standards. Mid-term plans include:

- electrical parameters of all system elements,
- power flows,
- network elements capacities (including data about capacity utilization and free capacities),
- short-circuit currents in each node,
- network nodes load,
- basic electrical parameters of consumption and production units,
- transmission losses,
- planned network reinforcements and/or network topology changes,
- system configuration etc.

Planning standards imply technical standards and they are divided in:

- standards related to normal operation,
- standards-criteria related to disturbed operation.

Standards related to normal operation include:

- voltage deviations from rated values for $\pm 5\%$,
- nominal frequency is 50 Hz and permitted deviation is $\pm 0,1$ Hz,
- consumers with power factor lower than 0,95 have to install reactive compensation devices.

Standards and criteria related to disturbed system operation include the (n-1) criterion and dynamic stability criterion. The (n-1) criterion is applied for the loss of one network branch (overhead line, cable, transformer, interconnection line) or any generator, and has to be satisfied for the most unfavorable system conditions. That outage must not lead to the following consequences:

- voltage and frequency deviations outside permitted ranges and current over-loadings that may be dangerous for secure system operation or that may cause equipment damage or life time reduction,
- loss of stability of any power plant or system in general,
- loss of load,
- disruption spreading over the system as a consequence of protection systems operation.

System stability has to be kept in all operational conditions.

4.1.7. Romania

The Technical Code in Romania defines, among other topics, criteria for transmission planning. Chapter 5 of the Code (ETN Development Planning) defines attributions and competencies, the goals of planning activity, elaboration of the transmission network development planning, the (n-1) criterion in the planning, technical stability criteria, technical criteria in dimensioning the compensation installations for the reactive power, verification and determination of the equipment short-circuit and nominal current maximum limit and other provisions [10]. National Electricity Company is obliged to prepare the perspective plan for each successive 10 years, with up-dating at each 2 years that has to be approved by competent authority and the ministry in charge. That plan has to be in compliance with the actual status and future evolution of electricity demand, indicating the modalities for the financing and implementation of the investments.

The goal of the transmission system planning activity is to provide the following:

- development of transmission network so that it should be correspondingly dimensioned for the transmission of electricity projected to be generated, imported, exported and transited,
- provide energy system operation under safety and security conditions and permit the transmission of electricity at corresponding quality levels of frequency and voltage,
- materialize the results of national energy system development planning activity through initiation of the procedures necessary for the promotion of the new investments in transmission network, evaluation of the long term marginal costs in each node of transmission network and supply of data for working out the transmission tariff systems.

The elaboration of transmission network development planning is based on the current situation of the demand, offers for the generation from existing power plants and other existing and potential network users, level of safety in operation for energy system on the whole and per each node, LOLP probability of non-providing the load and strategy for the development of the telecommunication infrastructure.

The (n-1) criterion is used for transmission network dimensioning. Verification of the (n-1) criterion is made for the maximum prognosticated transfer of power. While checking the (n-1) criterion for 400 kV and 220 kV network it is assumed that parallel 110 kV network is disconnected. To dimension the evacuation in system of the power generated in the nuclear power plants the (n-2) criterion is used. The (n-1) criterion is fulfilled if:

- The operation parameters of transmission network are within the limit parameters of the operation voltage and load current so that there exist no negative impact that can put in danger safe operation of the system or can lead to the deterioration of the equipment or non-acceptable reduction of equipment lifetime;
- No interruptions in the supply of transmission network users take place;
- No tripping of other installations takes place by the help of the equipment protection devices that are not affected directly by the perturbation involving the risk of its extension;
- No modification or interruption of the transfer of power resulted from the long terms covenants.

Technical criterion for static stability that has to be verified for a perspective of up to maximum 10 years, says that transmission network should provide a static stability of minimum 20 % with (n) lines in operation, and 8 % with (n-1) lines in operation.

Technical criterion for transient stability that has to be verified for a perspective of up to maximum 5 years, says that transmission network should provide stable operation for the multi-phase or single-phase 400 kV and 220 kV line with (n) and (n-1) elements in operation.

Dimensioning of the installations for the compensation of the reactive power is made with the observance of the acceptable voltage ranges in all the nodes, under all the operation regimes in configuration with (n) and (n-1) elements in operation.

The efficiency of the short and medium term investments in transmission network should be justified during the planning phase, based upon the escalated recovery duration at least. Long term planning studies (10 years) should indicate development solutions prioritized on economic criteria.

4.1.8. Serbia

Serbian Grid Code is under preparation (status February 2007).

4.1.9. UNMIK

UNMIK Grid Code is under preparation (status February 2007).

4.1.10. Slovenia

Slovenian Grid Code is a very reduced one concerning transmission system planning issues. It says that the Slovenian TSO is obliged to prepare 5-years transmission network development plans [11] and that the network shall be designed according to the (n-1) criterion. TSO uses that criterion in order to avoid one of the following events when one element is out of operation:

- excess of system parameters (frequency, voltage, current),
- cascade tripping,
- voltage instability,
- transient instability,
- loss of load.

The (n-1) criterion shall be satisfied for maximum power plants production.

4.1.11. Turkey

Transmission network planning issues and planning criteria in Turkey are published in the “Electricity Market grid Regulation” [12] and the “Transmission System Supply Reliability and Quality Regulation” [13] documents.

By taking into account the economic aspects of opportunities related to the connection to and/or use of the transmission system according to the capacity projections, TEİAŞ is responsible for preparing the transmission system ten year progress report, for the purpose of determining the most suitable regions for energy transmission and providing guidance to investors.

TEİAŞ is responsible for preparing the generation capacity projection that covers projection for minimum ten year period, based on the demand forecast prepared by distribution companies, in order to maintain the quality, continuity and reliability of electricity supply and also to lead the market participants.

Transmission system ten year statement report has the objectives of putting forth the opportunities of connection to and/or use of the transmission system, together with their economic aspects, identification of the most suitable regions for electric energy transmission and also leading the new market participants.

The transmission system ten year statement report includes the following items:

- basic parameters of the transmission system as of the end of the last year,
- regional characteristics of the transmission system,
- evaluation of the current performance of the transmission system,
- improvements planned on a yearly basis,
- investment plans of the transmission system,
- regional transmission tariffs.

TEİAŞ plans and develops the transmission system in accordance with the provisions set out in the transmission license. Users take into account TEİAŞ's views and practices in planning and improvement works concerning their own generation facility and/or network. Transmission system development plan prepared by TEİAŞ based on regulation clauses concerning security and quality of supply comes into effect following the approval of the Board. TEİAŞ publishes generation capacity projection and production safety criteria taken as a basis in the preparation of transmission system development plan. These criteria include calculations of the probability of not meeting the peak demand, based on finalized generation capacity projection.

Probability of not meeting the demand should be equal to or less than 2 % per annum, which indicates not meeting the peak load for a total period of seven days in a year. TEİAŞ includes its views in the annual connection opportunities report in order to reach annual generation capacity projection targets.

In [12] very detailed planning and design principles are defined. The transmission system is planned in order to ensure loading of the transmission system under the thermal limits, to ensure not loosing of even a user and in order to avoid island operation of the system, under normal operating conditions, under primary or (n-1) constraint and transport of maximum generation of generation facilities to the system conditions, via ensuring the voltage and frequency of the system is kept within the limits.

4.2. Regional grid code

In June 2005 EdF prepared preliminary proposal for future development of the Regional Grid Code [14]. This is the latest version of the document available to SECI project group. Planning issues are comprised in the "Planning Code" document.

It consists of the following chapters:

1. Introduction
2. Organization of system development planning
3. System reliability assessment
4. Data Exchange

Introductory part of the "Planning Code" says that the Planning Code has to specify the technical and organizational procedures and rules to be applied by all the members of the "regional electricity market" area in the planning and development of their own power system, and has to be taken into account in the overall planning and development of the SEE interconnected power system. The Planning Code is dedicated to serve the needs of the SEE electricity industry in a non-discriminatory access-to-transmission environment fostered by a changing sector structure and the creation of a common electricity market.

Chapter 2, Organization of system development planning, suggests planning principles at national level and regional electricity market level. The SEE TSOs should plan and develop their transmission network according to their own requirements and in compliance with UCTE technical

rules and standards. The SEE TSOs should prepare System Reliability Report every two years, covering time period of next 10 years. Every System Reliability Report should be based on:

- the forecast demand,
- an assessment of the generation adequacy: the generation development plan based on a regular estimation of the total generating capacity should meet the demand forecast with respect to the (n-1) criterion;
- an assessment of transmission system potential capacity;
- the need for interconnections with other (neighboring) power systems.

Principles of overall SEE planning are based on the aim to plan a system able to provide technical support for a regional power market. The Regional Grid Code suggests establishment of a Working Group that will deal with planning issues and prepare System Development Plan (SDP) every two years, covering time period of next 10 years. The main topics highlighted by the SDP will be:

- An inventory of possible deficits and surpluses of the generation-demand balance in each country;
- A list of network bottlenecks and power transfer limits between REM members' power systems; and
- A list of proposals for the construction of new tie-lines and correlated enhancements of individual transmission systems.

Chapter 3, System reliability assessment, defines power system adequacy issues, power system security issues, defense plan and re-energizing plans issues. For the purpose of this Study only first two items are commented.

Power system adequacy, as the criteria measuring the capacity of a power system to supply the aggregate electric power and energy demand of customers at component ratings and voltage limits, taking into account planned and unforeseen outages of system components, has to be assessed taking into account both the generation and transmission aspects. Assessment of the generation adequacy consists of investigating the ability of the generating units to match system demand evolution using a comparison between the demand and the total generating capacity which is considered as "guaranteed". Assessment of the transmission adequacy consists in investigating whether the transmission system is sufficiently sized to accommodate the potential imports and exports resulting from the various national power balances, thereby improving the reliability of the SEE interconnected power system.

It is prescribed that each SEE TSO for the national level, and WG on the regional level, shall estimate generation adequacy (together with power balance forecast and remaining capacity forecast). Transmission adequacy assessment consists of comparing the Remaining Capacity with the Net Transfer Capacity at the borders (the power that can be safely transmitted across the borders) of each SEE TSO. The SEE transmission system development forecast should be derived from the individual SEE TSO forecasts and agreed between them.

At the SEE level, the transmission system adequacy analysis focuses on the interconnections and on the internal lines, which have a direct effect on the international exchanges. The WG responsible for regional planning has to establish various scenarios for interchanges and power injections

according to the regional market. In addition, sensitivity analysis should be performed taking into account hydrological situations, market price fluctuations, etc. The WG has to assess the SEE transmission system adequacy. In case inadequacies are pointed out, the concerned TSOs have to look for a common solution.

The SEE interconnected transmission systems have to be planned, designed, and constructed so that with all the transmission facilities in service and with operating procedures in effect, the network can deliver generating unit output to meet the whole range of forecast customer demand and transmission services, in the following conditions:

- a. Line and equipment loadings are within applicable thermal rating limits;
- b. Voltage levels are within applicable limits;
- c. Short circuit current is within the limits; and
- d. Stability of the power system is kept.

The security criteria measure the ability of a power system to withstand sudden disturbances such as electric short circuits or unforeseen tripping of system components or loading conditions as well as operating constraints. The Planning Code prescribes the following security criteria for network planning:

1. The (n-1) criterion
2. Voltage and reactive power control criteria
3. Stability criteria
4. Short-circuit criteria

1. The (n-1) criterion

The (n-1) criterion is satisfied if, after a single system element has failed (e.g. transmission line, transformer, generating unit, etc.), the following rules are satisfied:

1. No breach of the limiting values for network operation variables (operation voltage, voltage ranges, frequency, network short-circuit power) that may endanger the security of the power system or lead to an unacceptable strain on equipment, damage, destruction or an inadmissible reduction in the life of equipment;
2. No inadmissible overloading of components may take place;
3. The voltages and frequency are satisfactory for consumers and generating units;
4. Interruptions of supply are avoided (with or without the use of redundancies temporarily available in lower voltage networks and in the installations of transmission system users);
5. Secondary tripping through activation of further protection devices on equipment not directly affected by the disturbance cannot involve the risk of spreading the disturbance;
6. There is no need to change or, if necessary, interrupt power transfers; and
7. The loss of generating unit stability is avoided.

The SEE interconnected power system has to be planned, designed and constructed so that the network can be operated to supply customer demand and transmission services, at all forecast demand levels, in accordance with the (n-1) criterion. As an ultimate objective, the SEE interconnected power system should be capable of accommodating planned equipment maintenance outages and continuing to operate in the condition specified by the (n-1) criterion.

2. Voltage and reactive power control criteria

Sufficient reactive resources have to be located throughout each power system, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply. Reactive power generation and consumption should be situated as close to each other as possible in order to avoid reactive power transmission and so that they can be applied effectively during normal conditions and when contingencies occur. Duties of the SEE TSOs are:

- Voltage control is primarily a local problem, which will therefore be under each SEE TSO responsibility;
- Each SEE TSO will plan reactive resources for its requirements and to maintain its control voltage capability. The planning has to take into account the influence of tie-lines on neighboring power systems;
- To compensate for an excessive consumption of reactive power, each SEE TSO has to be sure that dedicated producers will feed enough quantity into networks in addition to that produced by other devices installed in the networks or in consumers' installations;
- Each SEE TSO will conduct assessments (at least every five years or as required by changes in system conditions) to ensure reactive power resources are available to meet projected customer demands. Documentation for these assessments should be provided on request;
- Policies and procedures for boundary substations and installations must be developed with neighboring TSOs if appropriate; and
- Power flow simulation of contingencies, including P-V and V-Q curve analyses, could be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.

Where voltage deviations lead to constraints on the neighboring power systems on a regular basis, compensation equipment must be installed in order to keep the system voltage within the normal range. The choice of compensation equipment to be used will be agreed between the TSOs concerned.

3. Stability criteria

Stability calculations should be performed for the SEE interconnected power system. The regional planning WG should establish a set of common objectives for performing stability calculations in

order to ensure power system security. Thus, they should identify the scope and specificity of the steady-state and dynamic data required for reliability analyses and the procedures for data reporting. The WG should co-ordinate the stability study in order to examine that neither the national system stability nor the regional stability would be endangered by purchases or injections by the system users. When certain levels of power transfer are observed to produce a destabilizing effect, they must be examined. Thus, the WG should suggest actions to prevent or eliminate the risks and consequences such as:

- Steady-state instability prevention: The loss of small-signal stability could be prevented by optimized system control means, employment of Power System Stabilizers (PSS), changing of connectivity, etc.
- Transient instability prevention: The loss of transient stability could be prevented by the actions of the protection and control equipment or (if feasible) by fast-valving actions at power plants.

4. Short-circuit criteria

Short circuit calculations must be systematically carried out in every case so that transmission system design and planning take into account the adjacent networks' contribution to short circuit power. The facilities and devices connected to networks must be designed to operate according to given current limits. Therefore each interconnected power system is to be developed within imposed constructive limits. In particular, technical requirements for generating units' connections must be defined in order to guarantee that short circuit currents remain below the established limits (short-circuit calculation must be done according to the UCTE method, IEC 60-909 publication). Each SEE TSO has to ensure that its system design guarantees that at any node on a power system:

- short circuit currents will not exceed the capacity of devices installed on that node, and
- a sufficient short-circuit power value is available for fault clearance by the protection system.

In order to establish a basis for each SEE TSO to assess the contribution of adjacent systems when calculating short-circuit currents, the regional planning WG should use an SEE network model to execute a calculation for the SEE interconnected power system every five (5) years and to get a consistent set of data.

4.3. Summary of planning issues in national grid codes and draft version of the regional grid code

Based on the review of the national grid codes and a draft version of the regional grid code on transmission network planning issues, the following may be concluded:

- Grid codes prescribe the SEE TSOs obligations related to transmission system planning reports and studies. Planning horizons vary from short-term (up to 1 year ahead) to long-term (up to 20 years ahead);
- Grid codes define the role of the transmission systems. National transmission systems have to enable reliable and secure system operation and continuous load supply. Regional aspects

of national transmission systems are not mentioned in the national grid codes so there is no reference point for regional transmission system planning;

- All national grid codes prescribe the usage of the (n-1) criterion in transmission system planning. Explanation of that criterion is very similar between countries and not permitted consequences of single outages are pretty much the same;
- Other technical criteria such as short-circuit or stability criteria are prescribed somewhere in national grid codes;
- Transmission investments economic rationalization is not mentioned in the national grid codes, except in general term in the B&H and Romanian ones;
- Probabilistic technical criteria for transmission system planning (loss of load probability) are mentioned only in Romanian and Turkish grid codes;
- National grid codes are prepared in line with a draft version of the regional grid code, and there are no larger disproportions between the national grid codes and the regional grid code concerning transmission system planning issues;
- Draft version of the regional grid code assumes creation of a working group that will plan the network on regional level, especially directing attention to interconnection lines and to those internal lines which have large impact to transfer capacities between different countries. The national grid codes do not envisage any working group at a regional level which may deal with national transmission system planning issues;
- It seems that the national grid codes and a draft version of the regional grid code do not satisfactorily respect market issues in transmission planning, especially concerning planning uncertainties, economic considerations of transmission investments, balance between security and costs, promotion of the private financing and congestion costs.

5. PREREQUISITES AND ASSUMPTIONS FOR SEE TRANSMISSION SYSTEM PLANNING ISSUES

5.1. Market structure and regulatory aspects

The basic assumption for the following chapters is that a unified regional electricity market will exist in the near future at the territory of South East Europe. Planning criteria and methodology are thus suggested to be respected by the SEE TSOs.

Well defined planning criteria and methodology at the regional level may help the SEE countries to develop their power systems and infrastructure to serve common electricity market in accordance to the Energy Policy for Europe (EPE) [15]. Meeting the objectives from the EPE of sustainability, competitiveness and security of supply will surely help the SEE countries to better integrate into future common European electricity market. That includes development of new infrastructure needed to integrate electricity generated from renewable sources, infrastructure which leads to effective competition and reduces the scope for market power abuse and infrastructure which will increase security of supply.

The SEE transmission network planning criteria and methodology are defined observing national networks at the territory of the SEE, under the responsibility of the SEE TSOs, as a unique network, with the aim to promote and ensure market activities. Planning criteria and methodology are defined taking into account national requests defined in the national grid codes as much as possible, but suited to the regional electricity market needs. They serve primarily to support market activities at satisfactorily level of overall system adequacy and security, based on technical and economic considerations. They also serve to estimate the level of future SEE power system reliability and to identify and prioritize transmission investment candidates from the SEE regional point of view.

Basic assumption for the work conducted in this Study is that a stable regulatory framework and a necessary degree of co-ordination between the SEE TSOs in terms of technical standards, balancing rules and congestion management mechanisms will be achieved in the near future. More efficient unbundling of the SEE TSOs from production and supply companies may lead to more incentives to develop the network in the overall interest of the market and the SEE region as a whole.

It is supposed that the region of the SEE will have a well functioning electricity market organized through pool and bilateral contracts [16], and collectively regulated applying similar methods and procedures for congestion management, system security and quality and other issues. For the transmission system planning purposes, it is also supposed that production companies will give their bids to the pool at the regional level and that generators will be engaged on the basis of increasing bids to supply all consumers in the region. Consumers will have the right to choose suppliers wherever they want and suppliers will have the possibility to buy electricity from the pool or through bilateral contracts. Thus, it is assumed that electricity price will be market oriented across the region and not significantly dependent on the location in the SEE grid. For the planning purposes, especially concerning determination of projects regional impact and their prioritization, it is suggested that undelivered or unsupplied electricity unit value should be treated equally in the region and determined as the ratio between the sum of GDP's of the SEE countries divided by annual delivered electricity to all consumers in the region.

In other words, the SEE region is observed as one power system with same obligations and rights for all market participants and transmission network planning criteria and methodology are set to keep the overall system adequacy and security in the most economic way.

In order to respect obligations of the SEE TSOs in national transmission system planning, two groups of project candidates are made. The first group is made of project candidates significant at national levels which stay under the control of the SEE TSOs, while the second group is made of project candidates with possible regional impact. Planning criteria and methodology may be applied to project candidates from the second group only, in order to estimate their regional impact and to prioritize them. Such approach keeps the responsibilities of the SEE TSOs in transmission system planning under their control, but it also gives an appropriate signal to financial institutions related to the SEE regional market and its transmission system necessary development.

Important assumption for the effective usage of planning criteria and methodology proposed in this Study which will lead to transmission network investments with regional significance is an acceleration of authorization procedures (construction of a new transmission line may last more than 10 years under existing conditions). Dynamic and fast development of the SEE transmission system will support predicted fast growth of trading activities inside the electricity market and fast integration of renewable energy sources (construction period for a new wind power plant is up to three years), which will be impossible if complicated authorization procedures remain unchanged.

Environmental aspects in the SEE transmission system development have to be observed and respected in the most efficient manner. This will help to speed up the construction of transmission facilities by making them more acceptable for the public.

At last, private initiatives and PPP (Public-Private Partnership) in the SEE transmission system planning and development should be stimulated by market oriented signals. Private interest is important aspect with respect to economic rationalization of network investments and has to be respected and promoted.

5.2. Uncertainties

The SEE transmission system planning should include the most important uncertainties that may arise in the future. According to the planning horizons (short, medium, long term planning), there are different types of uncertainties that have to be included in analyses. The most important uncertainties that should be observed in network planning are:

- new power plants size and locations,
- hydrological conditions,
- generators bids,
- branches and generators availability,
- load prediction, and
- regional power balance.

According to a planning horizon, following uncertainties have to be included:

Short-term planning (up to 1-3 years)

- hydrological conditions and generators engagement (at least 3 scenarios: dry, normal and wet hydrology),
- branches and generators availability,
- regional power balance (at least 3 scenarios: balanced region, import, export).

Mid-term planning (up to 5 years)

- hydrological conditions (at least 3 scenarios: dry, normal and wet hydrology),
- generators bids (at least 2 scenarios dependent on predicted fuel price),
- branches and generators availability,
- regional power balance (at least 3 scenarios: balanced region, import, export).

Long-term planning (up to 10 years)

- load prediction (at least 2 scenarios: normal growth rate, higher growth rate),
- new power plants size and locations (at least 2 scenarios as the result of Generation Investment Plan),
- hydrological conditions (at least 3 scenarios: dry, normal and wet hydrology),
- generators bids (at least 2 scenarios dependent on predicted fuel price: present fuel prices, significantly higher gas price),
- branches and generators availability,
- regional power balance (at least 3 scenarios: balanced region, import, export).

Description of the most important uncertainties is given as follows.

1. New power plants size and locations

The SEE generation adequacy and remaining capacity will have to be estimated according to [14]. Power plants construction plan is highly uncertain in long time frame. There are different construction candidates using different types of fuel and situated in territory of different market participants: nuclear power plants, coal fired power plants, combined cycle power plants, hydro power plants, renewables (especially wind turbines) etc.

Transmission network should be designed to connect future power plants without any restrictions in the evacuation of their power and without any congestions which may arise from new power plants production. So it should be planned according to at least 2 scenarios derived from the Generation Investment Plan. Those scenarios may be dependent on the future fuel prices (for example the 1st scenario assumes that fuel prices will remain the same, the 2nd scenario assumes that nuclear fuel and coal price will remain the same as today but natural gas price will rise on certain level much higher than today or the 3rd scenario assumes the renewable energy sources penetration - low penetration or high penetration of renewables).

In accordance to the European Energy Policy special attention should be directed to the integration of renewable sources into the grid. One generation investment scenario may be defined assuming high integration of renewable sources at distribution (small wind power plants, fuel cells, small hydro etc.) and transmission level (large wind power plants).

Generation investment plan that has to be periodically updated is the base for transmission network planning. It gives different scenarios relevant for network planning.

2. Hydrological conditions

The SEE area has a lot of hydro power plants with production dependent on the hydrology. National networks are designed to support hydro production and load supply for different hydrological conditions (ranging from very dry to very wet hydrology). At least three scenarios should be relevant for transmission system planning:

- a) hydro generators engagement during dry hydrological conditions,
- b) hydro generators engagement during normal hydrological conditions, and
- c) hydro generators engagement during wet hydrological conditions.

3. Generators bids

Uncertainty resulted from unknown future production companies bidding behavior (especially those generators with significant variable costs such as thermal power plants) should be included into network planning defining at least 2 scenarios dependent on future fuel prices:

- a) generators bids (production costs or fuel costs) remain as today, and
- b) nuclear and coal fired power plants bids remain the same, but combined-cycle and oil fired power plants bids rise to higher level.

4. Branches and generators availability

Uncertainties in lines, transformers and generators availability, because of planned and non-planned outages, should be taken into account during probabilistic analyses of power system operation and economic analyses of network investments profitability.

5. Load prediction

Uncertainties of load growth should be taken into account during long-term network planning and be considered using at least two scenarios:

- a) normal load growth rate,
- b) higher load growth rate.

6. Regional power balance

Observing the region of the SEE and its neighboring electricity markets and power systems, it is unknown whether electricity / power will be imported to the region, exported from the region or the exchanges will be near zero level. Regional power balance strongly depends on the observed hydrological conditions. If hydrology is favorable one may expect that power will be exported from the region, while for normal and dry hydrological conditions power may be imported in the region or the region may be balanced. Scenarios of different regional power balance have to be coordinated and adjusted with scenarios dependent on hydrological conditions:

- a) balanced SEE region (during normal and wet hydrology),
- b) power import in the SEE region (during dry and normal hydrology),
- c) power export from the SEE region (during wet hydrology).

Different planning scenarios dependent on the uncertainties and planning time-frame are shown in Appendix 4.

Additional scenarios with bulk power transits in different directions may be defined and applied in transmission system planning.

In the short-term planning uncertainties related to hydrology, the regional power balance and branches and generators availability should be taken into account. It results in 10 scenarios to be analyzed. For probabilistic (economic) analysis (see Chapter 7.3.1) branches and generators availability may be taken into calculation by using random sampling so there are only 5 scenarios to be analyzed (uncertainties related to hydrology and regional power balance).

In mid-term planning uncertainties related to hydrology, generators bids, regional power balance and branches and generators availability should be taken into account. It results in 20 scenarios to be analyzed. For probabilistic (economic) analysis there are 10 scenarios to be analyzed (branches and generators status of operation may be randomly determined).

The Long-term planning results in the highest number of scenarios (80 scenarios) because the uncertainties related to load growth, new power plants size and locations, hydrology, generators bids, regional power balance and branches and generators availability should be taken into account. Number of scenarios may vary, depending on the number of Generation Investment Plan (GIP) scenarios (80 scenarios if 2 GIP are taken into consideration). For one GIP there are 40 scenarios dependent on the load growth, hydrology, generators bids, regional power balance and branches and generators availability. For probabilistic (economic) analysis there are 20 scenarios to be analyzed for one GIP.

Number of planning scenarios in the short-term, mid-term and long-term time horizon may vary, depending on the uncertainties which are chosen to be modeled by transmission planners.

5.3. Transmission investments financing

Transmission system investments are financed by the SEE TSOs through transmission fees and loans according to national legislation. National regulatory authorities have to approve network investments and allow the inclusion of investment costs into transmission fees.

This Study does not observe the problem of investments financing. Problems may arise if any SEE TSO is not satisfied with the SEE transmission system development plan, made according to the criteria and methodology defined here, and rejects to invest in some new line with regional market significance (with not so obvious benefit for national network and system under control of that TSO). Adequate mechanism for investments financing on the territory of one TSO but beneficiary for another TSOs or market players has to be found in the framework of the Energy Community. Otherwise, the adoption of planning criteria and methodology suggested in this Study will be more complicated, if not impossible.

Private investments should be stimulated also by the SEE TSOs, regulatory authorities and respective EU bodies.

5.4. Interconnection and internal lines

Although a larger number of the SEE TSOs do not have any specific criteria for interconnection lines construction, there was always higher level of analyses related to interconnection lines than to internal ones. Some TSOs in the SEE region have established specific economic criteria for interconnection lines based on difference in electricity prices or on the overall change in system operational costs derived by different interconnection options and different working regimes of power systems.

With the market development it is expected that congestion costs will become a very influential factor for interconnection lines construction. Nevertheless, transfer limits on interconnection lines in SEE are often related to internal network problems, and rationalization of investments in new interconnection capacity may cause that internal problems stay hidden. Furthermore, SEE TSOs may declare lower values of Net Transfer Capacity in order to protect domestic power producers from market activities or to keep unnecessary high level of security of a system under their control because of different reasons (fear of incidental situations, lack of possibility to control system variables, lack of knowledge in system control, unsatisfactory organization of dispatching services, lack of procedures for system control etc.).

Having in mind that planning criteria and methodology are set in this Study for the SEE region as a whole, the treatment of interconnection lines and internal national lines have to be the same. That means that suggested criteria and methodology have to be applied equally to interconnection lines between different SEE TSOs and internal power lines inside national networks. If the SEE region is treated as one market and one power system, national boundaries must not cause different treatment of power lines and network should be planned across one unique area with interconnection lines only between the region and neighboring markets and power systems. Equal treatment of interconnection and internal lines in the SEE transmission system planning should stimulate the SEE TSOs to invest more in internal lines and increase NTC values on the national borders that are generally reduced by internal network problems. It should be stressed out that interconnection capacities between the SEE countries are much more developed than in the western European

countries. The largest number of the SEE countries has interconnection capacities larger than its system load, but declared NTC values may be much lower due to internal network problems.

If the SEE electricity market will be organized around the pool and bilateral contracts, and transmission fees will be unified and paid according to the post-stamp method, electricity price should be similar across the region. Similar electricity price in the SEE region additionally removes differences between interconnection and internal lines. Otherwise, if electricity prices will be different across the region, criteria for new interconnection lines construction between neighboring TSOs should be based on the difference in electricity prices and reduction of congestion costs.

Planning criteria for power lines between the SEE countries and other markets and power systems should be based on economic rationales, taking into account possibilities for expanding market activities (power import, export) and differences in electricity prices on different markets.

6. TRANSMISSION NETWORK INVESTMENT CRITERIA

6.1. Technical criteria

Technical criteria for the SEE transmission system planning are used for technical evaluation of the candidate projects for transmission network reinforcements (hereinafter *candidate projects*). Technical criteria include:

- 1) The (n-1) criterion,
- 2) Voltage and reactive power criterion,
- 3) Short-circuit criterion, and
- 4) Stability criterion.

6.1.1. The (n-1) criterion

The (n-1) criterion is satisfied if, after a single system element has failed (e.g. transmission line, transformer, generating unit, etc.), the following rules are satisfied:

1. No breach of the limiting values for network operation variables (operation voltage, frequency) that may endanger the security of the power system or lead to an unacceptable strain on equipment, damage, destruction or an inadmissible reduction in the life of equipment;
2. No inadmissible overloading of components may take place;
3. The voltages and frequency are satisfactory for consumers and generating units;
4. Interruptions of supply are avoided (with the use of redundancies temporarily available in lower voltage networks and in the installations of transmission system users);
5. Secondary tripping through activation of further protection devices on equipment not directly affected by the disturbance cannot involve the risk of spreading the disturbance;
6. There is no need to change or, if necessary, interrupt power transfers; and
7. The loss of generating unit stability is avoided.

The (n-1) criterion is related to the loss of:

- single-circuit overhead 400 kV or 220 kV line (interconnection or internal line),
- one circuit of double-circuit overhead 400 kV or 220 kV line (interconnection or internal line),
- cable 400 kV or 220 kV,
- transformer 400/220 kV,
- the largest generator in a power plant connected to 400 kV or 220 kV grid.

Loss of both circuits of double-circuit overhead lines, several cables inside the same cable route and bus-bars are not observed as (n-1) contingency, unless some special circumstances like nuclear power plants grid connection are not observed.

During the (n-1) security check only 400 kV, 220 kV and important parts of lower voltage networks should be monitored for overloads. Overloadings in 110 kV networks are considered as a local problem which should be solved by national TSO.

Transmission system ability to satisfy the (n-1) criterion is checked by conducting power flow calculations during regional peak load and summer maximum load conditions, for all scenarios related to the future uncertainties (Chapter 5.2 and Appendix 4). Maximum permitted loadings of branches (lines and transformers) and permitted voltage range are determined by the SEE TSOs for the networks under their control, in accordance with their national grid codes. Maximum permitted line loadings should not be less than thermal ratings or overcurrent protection settings. Maximum permitted transformers loading should not be less than transformers rated power. Permitted voltage ranges are defined by national grid codes (Table 5).

Table 5 Permitted voltage range ($U_{min} - U_{max}$)

| Country | Voltage level | | | |
|------------------------|---------------|-----------|-----------|---------------|
| | 400 kV | 220 kV | 150 kV | 110 kV |
| Albania | 380 – 420 | 198 – 245 | - | 99 – 121 |
| Bulgaria | 380 – 420 | 198 – 245 | - | 99 – 123 |
| Bosnia and Herzegovina | 380 – 420 | 198 – 242 | - | 99 – 121 |
| Croatia | 380 – 420 | 198 – 245 | - | 99 – 121 |
| Macedonia | 380 – 420 | 200 – 240 | - | 99 – 121 |
| Montenegro | 360 – 440 | 198 – 242 | - | 104,5 – 115,5 |
| Romania | 380 – 420 | 198 – 242 | - | 99 – 123 |
| Serbia | 380 – 420 | 198 – 242 | - | 99 – 121 |
| UNMIK | 380 – 420 | 198 – 245 | - | 99 – 121 |
| Slovenia | 380 – 420 | 220 – 245 | - | 104,5 – 123 |
| Turkey | 370 – 420 | - | 146 – 162 | - |

During the (n-1) analysis in system planning, the following fast dispatchers actions should be observed (within 30 minutes after contingency has occurred) if possible:

- generators re-dispatching (only generators with the possibility of fast change in production outputs are observed),
- usage of voltage and/or power flow control on regulation transformers,
- usage of existing compensation devices (switching on/off), and
- network sectioning or changes in network topology.

These actions are observed only if branches overloadings during (n-1) contingencies are not larger than 20 % above permitted current or power limits, or if voltage deviations are not larger than $\pm 10\%$ in 400 kV network and $\pm 15\%$ for 220 kV and 110 kV networks.

The (n-1) criterion is satisfied if one dispatchers action listed above turn the system back into equilibrium condition with permitted network operation variables (voltage, frequency, current), without loss of load and interruption of power transfers.

Each candidate project which solves the problem related to the (n-1) security has to satisfy economic criterion to be included into future network configuration.

6.1.2. Voltage and reactive power criterion

Sufficient reactive resources, available for usage immediately after TSO request, have to be located throughout each power system, with a balance between static and dynamic characteristics. Reactive power generation and consumption should be situated as close to each other as possible in order to avoid reactive power transmission and so that they can be applied effectively during normal conditions and when contingencies occur.

Dimensioning of the installations for the compensation of the reactive power is made with the observance of the acceptable voltage ranges in all nodes, under all operation regimes in configuration with (n) and (n-1) elements in operation.

Voltage control is primarily a local problem, which will therefore be under each SEE TSO responsibility. Each SEE TSO will plan reactive resources for its requirements and to maintain its control voltage capability. The SEE TSOs have to keep permitted voltages in all network nodes, especially including ones that are neighboring to other TSOs in all possible (n) and (n-1) circumstances.

Each SEE TSO has to conduct assessments to ensure reactive power resources are available to meet projected customer demands. Power flow simulations, including P-V and V-Q curve analyses, could be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.

Transmission system ability to satisfy voltage and reactive power criterion is checked by power flow and eventually stability calculations during regional peak and minimum load conditions, for all scenarios related to the future uncertainties (Chapter 5.2 and Appendix 4). This criterion is applied only for short-term and mid-term planning studies.

6.1.3. Short-circuit criterion

In order to check network facilities and related equipment parameters, short-circuit calculations have to be performed during transmission system short-term and mid-term planning. Short-circuit calculation must be done according to the UCTE method (IEC 60-909 publication), and it has to include complete SEE transmission network and influence of neighboring power systems. Short-circuit calculations have to be performed on planned network configuration, and they have to include calculations of maximum three-phase and single-phase subtransient short-circuit currents (I_{sc3} , I_{sc1}) for each network node between 400 kV and 110 kV.

The facilities and devices connected to the network must be designed to operate according to given current limits. Each SEE TSO has to ensure that its system design guarantees that at any node on a power system:

- short circuit currents will not exceed the capacity of devices installed on that node,
- a sufficient short-circuit power value is available for fault clearance by the protection system.

Replacement of devices connected to transmission facilities is planned when maximum short-circuit three-phase or single-phase current exceeds 90 % of maximum limit for analyzed device (facility). In order to satisfy the short-circuit criterion, network sectioning may be analyzed, but that measure must not jeopardize the (n-1) criterion.

6.1.4. Stability criterion

Planned network configuration in short-term and mid-term time frame has to satisfy stability criteria during large or small-scale system disturbances. We divide following stability types:

- angle stability (small-signal and transient stability),
- voltage stability.

Voltage stability studies should be performed occasionally by the SEE TSOs when voltage and reactive power analyses show that voltage instability may potentially occur.

Angle stability studies shall be performed periodically in the short-term and mid-term network planning, assuming planned network topology according to technical and economic criteria, for the most dangerous system conditions (peak load, heavily loaded large generators, large power transits etc.).

Angle stability criterion is satisfied for large scale disturbances if all generators continue to operate synchronously after the occurrence of large disturbance like short-circuit, removed by normal protection systems operation. Stability calculations have to determine the limit time value of short-circuits duration (Critical Clearance Time – T_c) for which stability is kept, in order to estimate stability margin. Critical Clearance Time should be calculated for lines which are part of corridors of important power transits. Steady-state scenarios for stability calculations should be determined by relevant SEE TSOs. Angle stability criterion is satisfied if Critical Clearance Time is larger than short-circuit duration (with respect to protection activation time) for all analyzed scenarios.

Angle stability criterion is satisfied for small scale disturbances if electromagnetic oscillations within the power system are damped for all operating conditions.

Planned network configuration should be examined according to stability criteria taking into account following possible large and small scale disturbances:

- near to bus-bars three-phase short circuits on 400 kV lines, removed by normal protection system operation,
- short duration transitory short circuits (up to 60 ms) on 400 kV lines close to large power plants.

Normal protection system operation assumes removal of short-circuits within time interval defined by each SEE TSOs for a network under its control.

6.1.5. Technical criteria examinations depending on planning time-frame

The following table presents suggested technical criteria that should be fulfilled depending on the planning time frame.

Table 6 Technical criteria depending on the planning time-frame

| Criterion | Planning time-frame | | |
|----------------------------|---------------------|------------|-------------|
| | <i>Short</i> | <i>Mid</i> | <i>Long</i> |
| (n-1) | √ | √ | √ |
| Voltage and reactive power | √ | √ | |
| Short-circuit | √ | √ | |
| Stability | √ | √ | |

Table 7 presents the summary of suggested SEE transmission system technical planning criteria.

Table 7 Technical criteria for SEE transmission system planning

| Planning time-frame | Topology | Analysed operating conditions | Technical criteria satisfaction | Permitted corrective actions |
|---------------------|---|--|--|---|
| Short | All branches and generators available (n) | SEE peak load SEE minimum load (1-3 years horizon) | $I_{lines} < I_{max\ lines}^*$ $U_{min} < U_{node} < U_{max}$ Stability criteria Short-circuit criteria | - automatic transformers regulation - switching of compensation devices - network sectioning |
| | One branch (line, transformer) or generator or compensation device unavailable (n-1) | SEE peak load (1-3 years horizon) | $I_{lines} < I_{max\ lines}^{**}$ $U_{min} < U_{node} < U_{max}$ | - generators re-dispatching ^{***} - automatic and manual transformers regulation - switching of compensation devices - network sectioning |
| Mid | All branches and generators available (n) | SEE peak load SEE minimum load (5 years horizon) | $I_{lines} < I_{max\ lines}^*$ $U_{min} < U_{node} < U_{max}$ Stability criteria Short-circuit criteria | - automatic transformers regulation - switching of compensation devices - network sectioning |
| | One branch (line, transformer) or generator or compensation device unavailable (n-1) | SEE peak load (5 years horizon) | $I_{lines} < I_{max\ lines}^{**}$ $U_{min} < U_{node} < U_{max}$ | - generators re-dispatching ^{***} - automatic and manual transformers regulation - switching of compensation devices - network sectioning |
| Long | All branches and generators available (n) | SEE peak load SEE minimum load (10 years horizon) | $I_{lines} < I_{max\ lines}^*$ $U_{min} < U_{node} < U_{max}$ | - automatic transformers regulation - switching of compensation devices - network sectioning |
| | One branch (line, transformer) or generator or compensation device unavailable (n-1) | SEE peak load (10 years horizon) | $I_{lines} < I_{max\ lines}^{**}$ $U_{min} < U_{node} < U_{max}$ | - generators re-dispatching ^{***} - automatic and manual transformers regulation - switching of compensation devices - network sectioning |

* may be defined separately for winter and summer operation

** may be defined assuming permitted short time overloading (within 30 minutes)

*** power plants with fast regulation only (within 30 minutes)

6.2. Economic criteria

6.2.1. Profitability index

The profitability index (*PI*) is defined as the ratio between expected annual benefit from candidate project and the annuity of its expected costs (*I*).

$$PI_i = \frac{EB_i}{EC_i} \quad (1)$$

where:

PI_i is the profitability index in year i ,
 EB_i is expected benefit from construction in year i ,
 EC_i is the annuity of candidate project expected costs.

Profitability indices for candidate projects have to be calculated for the whole planning horizon. Observed candidate project is economically profitable if:

$$PI_i > 1 \quad (2)$$

for all studied years i .

Candidate project is economically profitable and should be included into network configuration for the first studied year in which its profitability index is larger than 1, assuming that it stays larger than 1 for other future studied years as well. Special case may occur, when the profitability index is larger than 1 in studied year but it falls below 1 for future studied years - such project candidates are considered as not economically profitable.

The most important transmission candidate project is the one with the highest value of the profitability index. Economically profitable transmission candidate projects should be included into planned network configuration according to declined profitability indices (from the highest profitability index of a candidate project to the lowest but greater than 1).

Planned transmission network configuration should not contain any economically not profitable candidate project.

6.2.2. Expected benefit of transmission facility construction

The following types of benefit from candidate projects construction may be estimated for the purpose of economic criterion evaluation:

- benefit due to reduction of expected annual undelivered electricity costs,
- benefit due to annual losses reduction,
- benefit due to reduction of annual re-dispatching costs,
- benefit due to annual congestion costs reduction.

Total expected annual benefit from candidate projects construction is the sum of benefits defined above. Description of different benefit types is given as follows.

1. Expected annual undelivered electricity costs

For given operating conditions (defined by generation and load pattern, network topology etc.) network overloadings may be reduced or removed only by load reduction. This measure, whether caused by dispatcher decision or by automatic protection system operation, causes some expenses that can not be easily defined. Construction of new transmission system object or facility may decrease undelivered electricity costs.

Unit value of undelivered electricity costs (€/kWh) for the SEE region, for the transmission system planning purposes, is suggested to be determined as the ratio between the sum of GDP's (in €) of all SEE countries and the sum of delivered electricity in these countries for the observed planning year.

Recommendation is that unit value of undelivered electricity costs, for the purpose of the transmission system planning, should be equal across the SEE region in the future to avoid different treatment of countries participating in the market. Each node of the SEE transmission network should have the same unit value of undelivered electricity costs. If unit value of undelivered electricity costs is not the same across the region for the planning purposes, methodology for projects prioritization suggested in this Study will be discriminatory because it will favor candidate projects planned on the territory with larger undelivered electricity costs unit value. Due to simplicity, unit value of undelivered electricity costs should be independent on the value of electricity not supplied and duration of electricity reduction.

2. Annual losses reduction

Construction of every single new transmission object or facility (overhead line, cable, transformer etc.) generally decreases losses in a transmission system (although increase of losses is also possible but rarely). If we transform annual losses reduction into money value, clear benefit is visible from the construction of observed transmission object or facility. Cost of power losses for specific operational condition may be calculated as marginal price of the most expensive dispatched generator.

3. Annual re-dispatching costs

Transmission system planning methodology assumes that all generators are engaged according to the least-costs order (starting from the cheapest one to the most expensive one for a given system load). This may be possible only if there are no constraints in a transmission system. If some constraints occur in transmission system, network overloadings or perturbation of system variables (voltage, current) may be avoided by different generators engagement that will result in increased overall production costs (and the electricity price in a given moment). Observing one planning year, annual re-dispatching costs as the difference between generators engagement due to transmission constraints and ideal engagement according to increasing production costs (bids) may be estimated. Construction of new transmission system object or facility may help to avoid some transmission system constraints and thus to decrease re-dispatching costs.

4. Annual congestion costs

Network congestion occurs when all market transactions are not possible or allowed because of network overloadings. Depending on applied congestion management method, congestion costs are calculated. Transmission investments may decrease congestion costs and thus create more efficient market.

6.2.3. Expected costs of transmission facility construction

The following types of costs from candidate projects construction may be estimated for the purpose of the economic criterion evaluation:

- investment costs,
- operation and maintenance costs.

For the planning purposes, investment costs may be estimated using unit equipment price values (€/km of overhead line or cable, €/transformer, €/by etc.). Unit equipment price values for the SEE that will be used for planning purposes have to be determined by the SEE TSOs.

Operation and maintenance costs may be estimated as 2 % of the overall network facility or object investment.

The annuity of expected costs (EC_i) is calculated according to (3), assuming that expected life time of 45 years is valid for all candidate projects.

$$EC_i = \frac{d \cdot (1,02 \cdot I)}{1 - \frac{1}{(1+d)^N}} \quad (3)$$

where:

- EC_i is the annuity of expected costs of a candidate project,
- I is total investment in a candidate project,
- d is discount rate, and
- N is expected life time of a candidate project (N=45)

For the purpose of planning, assumption that all costs (investment, operational and maintenance) are divided into equal annual values during expected life time is made in order to allow comparison between expected annual benefits and annual costs. Experience shows that expected life time of transmission facility or project candidate is larger than its amortization period. Life time of 45 years is estimated as relevant for overhead lines, cables and transformers.

Discount rate that will be used for the SEE transmission system planning should be determined by relevant institutions (the SEE regulatory authorities, the SEE TSOs etc.).

7. METHODOLOGY FOR PROJECT PRIORITIZATION

7.1. List of candidate projects

The SEE TSOs are obliged to plan transmission systems under their control (national transmission systems). Their plans will include new facilities and objects, planned primarily to satisfy their national requests, obligations and criteria. Regional and market significance of these projects may be invisible or not estimated and taken into account. Unique list of candidate projects in SEE should be determined and each SEE TSO should define candidate projects according to their national plans and considerations. This list has to include technical and economical parameters of candidate projects, at least the following:

1. For new overhead lines

- predicted year of construction,
- voltage level,
- line length,
- connection nodes,
- material and cross-section,
- electrical parameters (resistance, reactance, susceptance),
- maximum permitted current,
- unit construction costs (€/km),
- total costs (€).

2. For new transformers and transformer stations

- predicted year of construction,
- rated voltages,
- connection nodes,
- rated power,
- electrical parameters (resistance, reactance, magnetizing admittance etc.)
- type of control and range of control.

The list of candidate projects prepared by each SEE TSO shall be divided into two parts:

1. candidate projects with local significance,
2. candidate projects with possible regional significance.

Only candidate projects with possible regional significance should be evaluated at the regional level, examined according to predefined technical and economic criteria and prioritized according to the methodology defined in this Study.

Regional transmission system planning group or institution responsible for regional planning is allowed to propose new candidate transmission projects, apart from the proposed list, based on the analyses and problems found during simulations.

Evaluation of transmission investments should be made on mid-term and long-term horizon, and studied years should be defined with 5 years interval between them (for example 2010, 2015, 2020 and so on).

7.2. Load flow analysis and security analysis

Load flow and security analysis have to be conducted within planning time-horizon in order to examine future network operation and identify possible constraints that may occur. Load flow and security analysis should start from the first year of the planning period, using network topology that does not include any new transmission facility defined in the list of candidate projects as “projects with possible regional significance”. Thus, initial network topology should include only new projects with local significance planned by the SEE TSOs.

Network modeling for load flow and security analysis should be prepared by the SEE TSOs, representing a network on the territory of their control. Models should be merged and one official model of the SEE transmission network should be prepared for each studied year inside the planning horizon. Network should be modeled in the PSS/E format (Power System Simulator for Engineers, Siemens PTI) which is used by all SEE TSOs. Models should contain voltage levels between 750 kV and 110 kV, without equivalent branches, with load modeled on the lowest voltage level (mostly 110 kV) and power plants modeled as groups of generators and unit transformers. Network topology should include all branches in operation, except those existing branches that will be permanently out of operation in a studied year. Concerning analyzed demand situation, three load levels shall be modeled:

1. winter peak load,
2. summer maximum load, and
3. summer minimum load.

Initial models should be used to create different models representing future uncertainties defined in Chapter 5.2 and Appendix 4. Institution or a working group responsible for the SEE transmission system planning has to define planning scenarios, generators engagement, regional power balance and other parameters important for network planning.

Load flow and security analysis should be performed for all future scenarios (Chapter 5.2 and Appendix 4), and network constraints should be recorded. All network constraints should be presented in a table form, as shown below.

- a) maximum current and power deviations with (n) available branches

| Planning scenario | Overloaded branch | Overloading (% I_{max} or S_r) |
|---|---|--|
| <i>Description of the analyzed scenario</i> | <i>Name of branch which is overloaded</i> | <i>Amount of overloading in percentage of maximum current or rated power</i> |

b) voltage range deviations with (n) available branches

| Planning scenario | Node | Voltage (kV) |
|---|---|--|
| <i>Description of the analyzed scenario</i> | <i>Name of nodes with voltages outside of permitted range</i> | <i>Absolute value of voltage which is out of range</i> |

c) maximum current and power deviations with (n-1) available branches

| Planning scenario | Branch outage | Overloaded branch | Overloading (% I_{max} or S_r) |
|---|---|---|--|
| <i>Description of the analyzed scenario</i> | <i>Name of branch which is out of operation</i> | <i>Name of branch which is overloaded</i> | <i>Amount of overloading in percentage of maximum current or rated power</i> |

d) voltage range deviations with (n-1) available branches

| Planning scenario | Branch outage | Node | Voltage (kV) |
|---|---|---|--|
| <i>Description of the analyzed scenario</i> | <i>Name of branch which is out of operation</i> | <i>Name of nodes with voltages outside of permitted range</i> | <i>Absolute value of voltage which is out of range</i> |

Local constraints in internal transmission networks which are not influenced by regional power transfers should be neglected.

List of recorded network constraints for all analyzed planning scenarios in a studied year is the base for project candidates' technical and economic evaluation that follows.

7.3. Other calculations

7.3.1. Probabilistic analysis

For the purpose of economic evaluation of candidate projects, declared by the SEE TSOs as “projects with possible regional significance”, and their prioritization, probabilistic analysis should be performed. Regional model for probabilistic analysis should include at least 400 kV and 220 kV voltage levels (and below if necessary), with load defined at the lowest voltage level included in the model. Power plants should be defined as one generator, without unit transformers because of simplicity.

Branches annual unavailability in percentage of total time (%), as well as generators (power plants) unavailability should be defined and estimated by the SEE TSOs for a network under their control, and divided into following categories:

1. planned unavailability (% of time per year) – unavailability caused by maintenance works and other types of activities that may be planned in advance,
2. accidental unavailability (% of time per year) – unavailability caused by unwanted accidental situations.

Probabilistic analysis should be conducted for different demand (load) levels. The SEE TSOs should provide their estimation of hourly load in a studied year(s) for a network under their control, and the SEE annual load duration curves should be constructed (Figure 2). Annual load duration curve for the SEE should be represented for probabilistic analyses with at least five areas:

1. Peak load situation (between 100 % of P_{max} and 95 % of P_{max});
2. Winter high load (between 94 % of P_{max} and 80 % of P_{max});
3. Summer high load (between 79 % of P_{max} and 65 % of P_{max});
4. Winter low load (between 64 % of P_{max} and 50 % of P_{max}); and
5. Summer low load (> 50 % of P_{max}).

Different branches and power plants unavailability categories shall be connected with different areas in an annual load duration curve. Accidental unavailability should be taken into calculations for peak load, winter high load and winter low load, while planned and accidental unavailability should be taken into calculations for summer high and low load.

Probabilistic analysis shall be performed for all planning scenarios defined according to future uncertainties (Chapter 5.2 and Appendix 4). For each planning scenario, benefits from candidate projects shall be evaluated taking into account different types of benefits defined in Chapter 6.2.2.

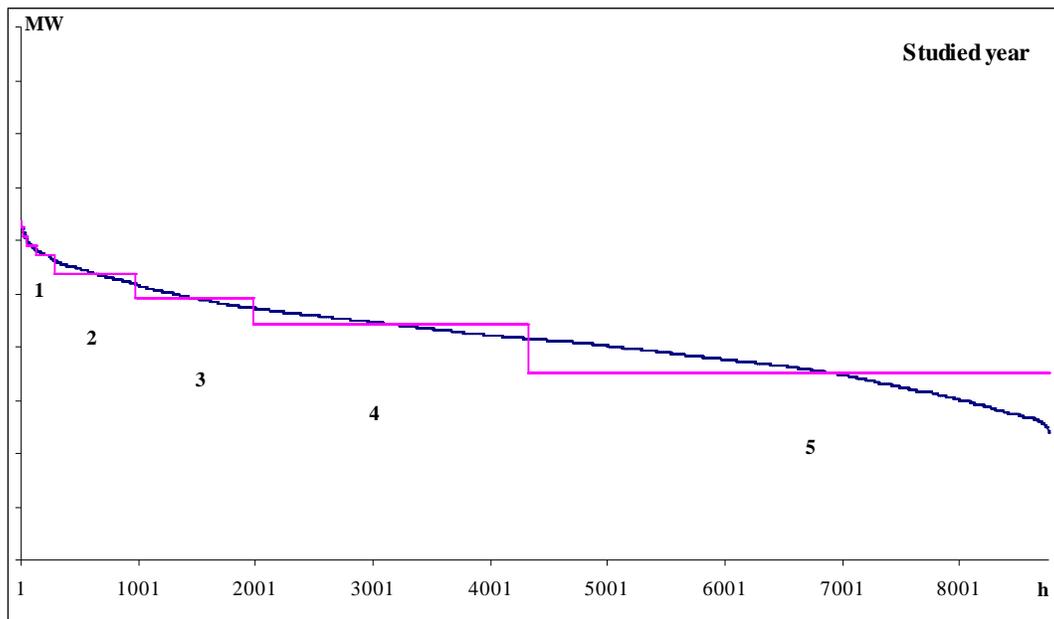


Figure 2 Load duration curve approximation

7.3.2. Short-circuit analysis

Short-circuit calculations should be performed in the short-term and mid-term planning period on the final network topology which includes candidate projects justified according to technical and economic criteria.

As previously stated, short-circuit calculation must be done according to the UCTE method (IEC 60-909 publication), and it has to include complete SEE transmission network and influence of neighboring power systems. Network should also be modeled in the PSS/E format (Power System Simulator for Engineers, Siemens PTI) which is used by all SEE TSOs.

7.3.3. Stability analysis

Stability calculations (small-signal stability, transient stability) shall be performed periodically for short-term and mid-term planning period on the final network topology which includes candidate projects justified according to technical and economic criteria. Network should be modeled in the PSS/E format.

7.4. Reviewed list of candidate projects according to the technical criteria

Separate application of technical and economic criteria in transmission system development evaluation and projects prioritization should be allowed, depending on readiness and availability of software tools. This Chapter suggests project prioritization according to the technical criteria.

Starting from the common list of candidate projects, nominated by the SEE TSOs as “projects with possible regional significance”, and conducted analyses of load flows and (n-1) security, candidate projects should be included into the network topology one by one. Then new load flow and security analysis have to be performed for all analyzed planning scenarios in a studied year. New list of network constraints has to be created, and constraints that are removed when new project is included into the network topology have to be highlighted.

New list of candidate projects has to be determined, that includes only those projects which lead to the satisfaction of the technical criteria in at least one planning scenario. In other words, only candidate projects which remove one or more network constraints (in monitored network 400 kV and 220 kV) in one or more planning scenarios in a studied year are included in the reviewed list of candidate projects.

Candidate projects which do not remove any network constraint are excluded from the list of candidate projects and are considered as regionally not significant in a studied year.

Candidate projects which are included in the reviewed list of candidate projects are technically prioritized according to network constraints that are removed by candidate projects:

- the first importance group contains candidate projects that remove network constraints with (n) available branches (the highest level of technical prioritization), and
- the second importance group contains projects that remove network constraints with (n-1) available branches (lower level of technical prioritization).

Inside these two groups of candidate projects, further technical prioritization is made according to:

- the number of planning scenarios in which candidate project removes network constraints (more planning scenarios with network constraints that are removed by candidate project, more technically significant is a project),

- voltage level of overloaded transmission lines (removal of overloadings on 400 kV lines are more significant than on 220 kV lines), and
- the number of network constraints that are removed by a candidate project (more constraints are removed, more technically significant is a project).

7.5. Evaluation of projects according to the economic criteria

Candidate projects that are included in the reviewed list of candidate projects and prioritized according to the technical criteria should be further evaluated and prioritized according to the economic criteria.

Evaluation and prioritization of candidate projects according to the economic criteria is based on the profitability indices, or on the basis of the ratio between annual expected projects benefit and costs annuity for a studied year. Candidate projects should be included into network topology of a model aimed for probabilistic analysis, one by one, and their benefits (Chapter 6.2.2) should be estimated. Costs should be estimated by using same unit equipment prices (Chapter 6.2.3). Profitability indices should be calculated for all planning scenarios and average profitability index as a ratio between total sum of profitability indices for planning scenarios and the number of analyzed planning scenarios should be determined.

Prioritization of the projects should be made according to the maximum average profitability index. Transmission facility or object with maximum average profitability index should be included into network topology for a studied year, and all calculations have to be repeated in order to find out a candidate project with the second highest average profitability index. This procedure should be repeated until there are no other candidate projects with profitability index larger than 1 in any planning scenario.

8. CONCLUSIONS

The Study analyzes the problem of planning and investments in the SEE transmission system within new open electricity market environment which is to be established in the near future. Transmission system planning criteria and methodology for projects prioritization are suggested from the SEE regional perspective. It should be stressed out that the SEE region includes many countries (9 Contracting Parties and 5 Participants to the Energy Community Treaty among them) with their own transmission system operators differently organized and positioned with respect to production and supply companies, with different obligations raised from national legislation and grid codes concerning transmission network planning issues. Finding a way to commonly plan and develop regional transmission system is not an easy task, and it should be fully coordinated and stimulated by all parties concerned (not only the SEE TSOs, but also by regulatory authorities and other market participants as well).

The approach used in this Study, mainly due to necessity to respect national planning standards defined in national grid codes and to establish regional planning criteria and methodology for projects prioritization at the same time, was to divide transmission construction projects into two groups: nationally important projects and projects with possible regional significance. Investment projects that are nominated by the SEE TSOs should be divided into these two groups and each TSO should be responsible for the projects of national interests, while only projects possibly important from the SEE regional perspective may be planned and prioritized according to criteria and methodology suggested here.

In the course of the work on this Study we became aware of the following:

- Planning criteria used by the SEE TSOs today are generally similar and mainly concentrated around the (n-1) security criterion;
- Market oriented transmission investments and investments from the regional perspective are not mentioned and satisfactory treated in national grid codes;
- National transmission networks are mainly planned according to technical considerations, while economic rationalization of new investments generally remains out of interest;
- Methods used by transmission planners are based on deterministic approach, while probabilities of different events (network failures, generator dispatch, branches availability etc.) are not treated satisfactorily. It does not allow better economic considerations of network development and inclusion of economic criteria into decision making process;
- The SEE transmission system planning process has to include different uncertainties which will occur in an open electricity market environment. The most important ones are generation investment plan(s) with size and locations of new generators, generators bidding behavior in the future, hydrological conditions, branches and generators future availability, load growth and regional power balance. This Study suggests multi-scenario approach when dealing with uncertainties. Transmission planning procedure is adjusted to that;
- Transmission development in the SEE region can be more effective and faster if the following requests are to be fulfilled: a) full independency of Transmission System Operators from production and supply companies; b) acceleration of national authorization procedures for transmission facilities construction; c) effective market design and stable regulatory framework; d) introduction of market oriented signals for transmission investments; e) attraction of private investments into transmission development; f)

coordination and full cooperation between the SEE TSOs in planning issues; and g) establishment of stable financing mechanism that would support regionally important projects;

- Because of large number of the TSOs over relatively small territory, which would be hard to coordinate and direct their attention to the SEE regional prospective projects, as their main concern remains within national territories, the establishment of an official SEE regional transmission planning group is suggested hereby, which should be supported by the Energy Community, the SEE TSOs, the SEE regulatory authorities and the European Commission. This group should deal with the SEE transmission system issues, collection of planning data, establishment of planning scenarios, preparation of common network models for necessary analyses (load flow, dynamic, short-circuit, probabilistic models), performance of analyses, comparisons of candidate projects and defined criteria, prioritization of the investments and publication of reports concerning the SEE transmission system future bottlenecks, prediction of congestions from the planning perspective and development suggestions.

Transmission system planning process consists of different mutually dependent analyses (technical and economical ones), so it is necessary to define the planning procedure that will be respected during planning process. Following steps in the planning procedure are suggested:

- 1) Collection of planning data (technical and economical ones);
- 2) Preparation of the list of candidate projects by the SEE TSOs for planning time horizon;
- 3) Definition of the planning scenarios;
- 4) Network modeling (for technical and economical analyses);
- 5) Identification of network constraints (load flow and security analysis);
- 6) Evaluation of candidate projects according to technical criteria;
- 7) Identification of the reviewed list of candidate projects;
- 8) Prioritization of candidate projects according to technical criteria;
- 9) Probabilistic analysis;
- 10) Prioritization of the candidate projects according to economic criteria;
- 11) Determination of the final network configuration in observed time horizon; and
- 12) Other technical analyses (short-circuit, stability, voltage).

Proposed SEE transmission system planning procedure is presented in Figure 3.

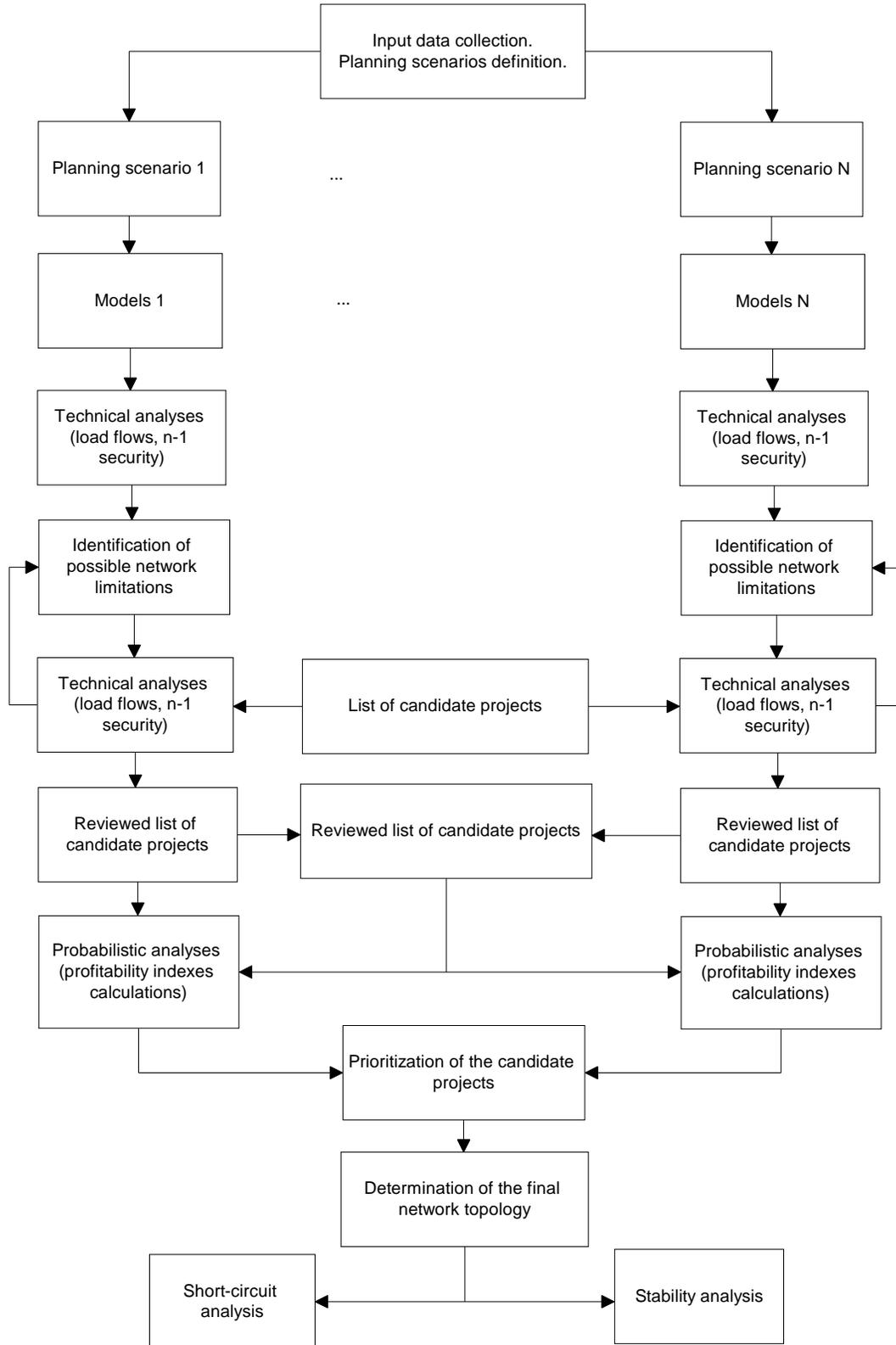


Figure 3 Proposed SEE transmission system planning procedure

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APPENDIX 1: TERMS OF REFERENCE

SECI PROJECT GROUP ON DEVELOPMENT OF INTERCONNECTION OF ELECTRIC POWER SYSTEMS OF SECI COUNTRIES FOR BETTER INTEGRATION TO THE EUROPEAN SYSTEM

Terms of Reference

Transmission network investment criteria

1. Background

1.1. Introduction

Transmission network planning has been strongly influenced by electricity market opening. Role of transmission system in a vertically integrated power supply company was to support economical dispatch of existing and future power plants with satisfying level of reliability in order to meet consumer present and future needs. Transmission network development was optimized to meet specific criteria with minimum expenses. Transmission planners were supplied with wide range of necessary data concerning future production, consumption and possible exchanges with neighboring countries. Prediction uncertainties were mainly connected to electricity consumption. Transmission networks were usually slightly or significantly over-designed in order to satisfy high level of consumption growth.

Several facts strongly influence transmission planning process under new conditions. These facts are:

- significant uncertainties that appear in an deregulated environment,
- lack of data needed for planning process,
- different transmission development objective functions, depending on the view of market players (producers, traders, suppliers, consumers, regulators),
- disproportion between technical, economical, environmental and social requests.

Although transmission planners were also faced to different uncertainties before market opening, existing and new uncertainties make transmission planning more difficult. Locations and capacities of new power plants, their bidding behavior, existence of the present ones in the future, consumer's reaction on instantaneous electricity price (price elasticity), electricity and power trading, capacity allocation mechanisms, regulatory aspects etc., are hard to be predicted even for the purpose of short-term planning. Standard deterministic approach, used before, is obviously not appropriate for new circumstances. Network development based on deterministic power flow analyses of several characteristic system conditions can't be approved any more. Incorporation of multi-scenario analyses is probably only temporary step in transmission network planning. Possible scenarios concerning power plants connection and dispatch, consumption growth and market transactions have to be carefully defined and coordinated between different parties such as transmission grid owners, system operators, market operators and regulators. Need to include many different uncertainties in network planning will probably lead to increased usage of probabilistic approaches in transmission network planning supported by risk analyses techniques.

The existence of different market players (producers, traders, suppliers), sometimes separated ownership and control responsibilities on transmission assets (TSO vs. ISO model) and separated companies (production, transmission, distribution, supply) caused the lack of data needed for transmission network planning. Confidentiality of some data and the lack of willingness to share them between different parties stress the problem additionally. One approach is to define necessary data needed for transmission planning that have to be exchanged between market players and transmission planners by regulating agencies. Otherwise,

transmission planners will be faced with additional uncertainties because they will have to predict some data and their assumptions can be wrong, depending on their knowledge on different aspects of electricity market issues. This is likely to lead towards underconstructed or overconstructed transmission network.

Each market player has different view on transmission adequacy and reliability today. Producer wants to give energy to a network without any limitations and he is not interested in what happens after his unit transformers or power plant busbars. Trader wants to buy wherever he finds energy and to sell it to someone without any restrictions and with minimum transmission and cross-border fees. Supplier wants to buy energy as cheaper as possible, while system operator has to allow all of this keeping the appropriate level of network security. Regulatory agency has to define that security level and to prepare an infrastructure for market in order to reduce or eliminate market power. Network congestions, today one of the main reasons for economical justification of network investments, may provide advantage for generators located in congested area giving them certain market power. Mathematically expressed, all of them have different target functions on transmission network adequacy and security. Instead of optimizing the sum, today we have sum of optimums. Achieving an optimal solution for everybody is impossible, so regulatory agencies obligation is to define unique target function that has to be met during transmission network planning. In other words, regulatory agencies have to define the task of transmission network and to define technical and economical criteria that have to be met by system operator and transmission network owner (usually merged in the same company), allowing them to include economically justified investments in transmission fee.

Transmission network have to satisfy different requests based on technical, economical, environmental and social perceiving. Technical requests are usually hard to meet while satisfying economical requests at the same time. Possible technical and economical solutions are usually restricted by environmental aspects. Social aspects has to be met (consumers have to be supplied) balancing economical considerations in transmission network operation and development. It is clear that optimal solution should represent a combination of socio-economical, technical and environmental requests.

1.2. Transmission network planning criteria

Network investments should be overviewed comparing them to predefined technical and economical criteria. Technical criteria should be defined on deterministic or probabilistic basis.

Mainly common deterministic criterion is (n-1), which proscribes technical requests that have to be met after one network branch or generator goes out of service. This criterion is based on the most restrictive system scenario, no matter of its probability of occurrence. This can lead to relatively high security margin during the planning process. Requests are usually connected with branch loadings and voltage profile in a network. Considered criterion could be strengthened observing loss of one generator and one branch (n-g-1), loss of two circuits (n-2) and simultaneous loss of one circuit while maintaining another one (n-1-1). Acceptable range of branch loadings could be defined as permanent maximum and short-term (up to ½ h) permitted overloading during which system operator could take appropriate actions to decrease critical branch(s) loading (re-dispatching, load reduction etc). Qualitative step forward could be more precise (from planning purposes) definition for maximum permitted branch loadings dependent on air temperature (maximum winter loading and maximum summer loading) and line corridors (urban, rural areas).

Deterministic criteria don't include probabilities of the failures in a network. More precise overview on network reliability could be achieved using probabilistic planning methods. Most commonly used probabilistic criterion in transmission network planning is loss of load probability (LOLP). Regulating agency should define the level of acceptable LOLP that transmission network has to meet. Different levels of acceptable number of outages and load reduction duration dependent on different load amounts could be defined also. In order to evaluate candidate network investments probabilistic simulation of observed power system should be done taking into account annual load duration curves. Similar approaches are expected to become more used in a deregulated environment especially because different uncertainties can be modeled in probabilistic simulations.

Most commonly used economical criterion in transmission network planning is positive Net Present Value (NPV). This criterion was used in vertically integrated companies also, but different definition of investment benefits had to be made after electricity market opening especially concerning congestion costs. Costs and benefits recognizing are crucial while observing economical criterion. Some other economical criteria like payback period or internal rate of return could be used also.

Crucial question while balancing technical and economical criteria is what if some investment satisfies technical but not economical criteria. Example could be found for a case in which technical (n-1) criterion is not satisfied only several hours per year during peak load situations. Probability that critical line will go out of service during those several hours per year is pretty small because lines availability are usually very high (99% or more). Consequence of this low probability is violation of economical criterion because expected line benefits are smaller than total costs. It seems that system operators accept such (n-1) violations forced by their regulated income which doesn't allow them such investments. In this example economical criterion will probably overmaster technical one. Other example can be found concerning busbar failures. Such failures are not observed by system operator usually, while planning transmission network, so they are not included in technical criterion. What if some busbar failure with very low probability causes extremely large costs (for example loss of load costs)? System operator or subject responsible for transmission planning will probably invest in new transmission line that connect load with other busbar to avoid large possible expenses of such fault. Economical criterion is now satisfied and technical one is not. Conclusion is that economical criteria are becoming dominant in open electricity market environment.

1.3. Regional planning

National TSOs are responsible for network planning within their countries. They develop and proscribe different planning criteria which they apply while planning a network. There is no example where one TSO or some other entity plans a network over wide area that includes responsibilities of several TSOs. Planning criteria applied by different TSOs may be the same or very similar, but responsibility of each TSO stays on its own territory.

In the SEE Region transmission network is owned and controlled by national TSOs. The Energy Community spreads over territories of the European Community and the following Contracting Parties: Croatia, Bosnia and Herzegovina, Montenegro, Serbia, Albania, Macedonia, Romania, Bulgaria and UNMIK. Each of them has its own system operator who is responsible for network reliability and security, as well as operational and planning aspects.



Planning of interconnection lines has been mutually coordinated by two neighboring TSOs. Interconnection lines are planned primary to increase transmission capacities between two countries, without taking into account regional needs. The challenge is to define planning criteria which will be applied not only to interconnection lines but also to internal lines inside an area of one TSOs responsibility, taking into account its regional importance.

1.4. The 8th Athens Forum conclusions

The 8th Athens Forum concluded that transmission investment criteria from regional perspective have to be defined, and transmission projects have to be prioritized according to those criteria. The aim of that conclusion is to support market activities inside the Energy Community and to remove barriers caused eventually by transmission network for free market trading.

2. Scope of Work

According to the conclusions from the 8th Athens Forum transmission investment criteria for the SEE region have to be defined in the study, taking into account regional needs. Transmission projects have to be prioritized lately according to those criteria.

The study should analyze the problem of transmission investment in an open market environment defining the most relevant uncertainties in the SEE region, review past experience on transmission network planning, analyze transmission planning criteria which have been used by different TSO in the region, review national grid codes and draft version of regional grid code, suggest transmission investment criteria from regional prospective, and methodology for project prioritization.

3. Preliminary contents of the Final Report

1. INTRODUCTION

2. TRANSMISSION NETWORK PLANNING IN AN OPEN ELECTRICITY MARKET

- 2.1. Transmission planning in the vertically integrated companies
- 2.2. Transmission planning in a market environment

3. EXISTING PLANNING CRITERIA

- 3.1. Albania
- 3.2. Bulgaria
- 3.3. Bosnia and Herzegovina
- 3.4. Croatia
- 3.5. Macedonia
- 3.6. Montenegro
- 3.7. Romania
- 3.8. Serbia
- 3.9. UNMIK

4. GRID CODES REVIEW

- 4.1. National grid codes
- 4.2. Regional grid code

5. PREREQUISITES AND ASSUMPTIONS

- 5.1. Market structure and regulatory aspects
- 5.2. Uncertainties
- 5.3. Transmission investment financing
- 5.4. Interconnection and internal lines

6. TRANSMISSION NETWORK INVESTMENT CRITERIA

- 6.1. Technical criteria
- 6.2. Economical criteria

7. METODOLOGY FOR PROJECT PRIORITIZATION

- 7.1. List of candidate projects
- 7.2. Load flow analysis and security analysis
- 7.3. Other calculations
- 7.4. Reviewed list of candidate projects according to the technical criteria
- 7.5. Evaluation of projects according to the economical criteria

8. CONCLUSIONS

4. Time schedule

Final Report has to be delivered three months after project beginning.

The Report on preliminary findings has to be prepared for the 9th Athens forum (October 2006).

APPENDIX 2: EXAMPLE OF TRANSMISSION NETWORK PLANNING IN THE VERTICALLY INTEGRATED COMPANIES AND IN A MARKET ENVIRONMENT

Test example of transmission system is presented in Figure A1. It consists of two generators (A and B), with maximum power 600 MW and 500 MW, and production costs of 1 money unit/MW and 2 money unit/MW respectively, three loads in nodes 2, 3 and 4 (with values of 300 MW, 100 MW and 500 MW respectively during peak condition) and five lines (1-2, 1-3, 1-4, 2-4 and 3-4) with same impedances except line 1-4 that has double impedance compared to the others. Maximum permitted lines loading during normal operating conditions is 300 MW for all of them. We observe only operation during full lines and generators availability, not taking into account (n-1) security. Otherwise, system is highly under-constructed concerning production and transmission facilities.

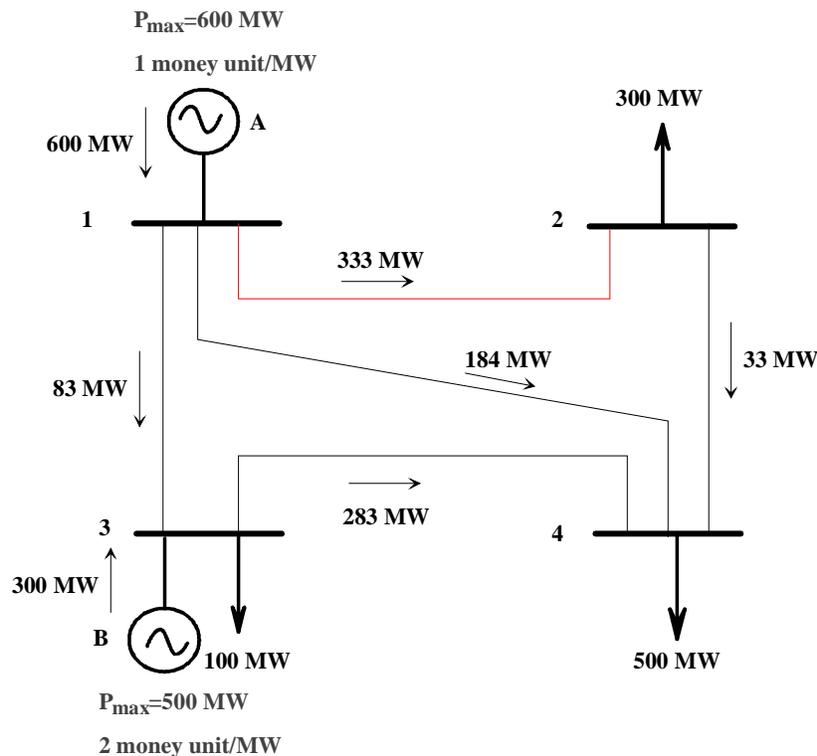


Figure A1 Transmission system test example

For the peak load situation power flows are calculated and line 1-2 is overloaded (333 MW comparing with the rating of 300 MW) if generators A and B are economically engaged (economically dispatched according to production costs). Power system simulation or optimization methods will lead to the necessity of network strengthening if:

- 1) load reduction is not acceptable or loss of load costs are high enough (if not, load in 2 may be reduced for 67 MW and network loading will be below permitted limits),
- 2) overloading can not be solved by generators re-dispatching or re-dispatching costs are high enough.

Two possible candidate lines exist which may solve the problem, parallel lines 1-2 and 1-4, but all methods will point out that line 1-2 has to be constructed because its investment costs are 2 times smaller than investment costs for line 1-4 that has double impedance or line length if the material and conductors cross section is the same for both lines.

Vertically integrated company will decide probably among two solutions shown in Figure A2. First solution (a) comprises construction of new parallel line between 1 and 2. In this example, loss of load is not acceptable for a vertically integrated company and only technical criteria in planning are applied (economical planning criteria are not considered). If loss of load is acceptable for a vertically integrated company this will lead to the second solution (b), in which load in node 2 have to be reduced for 67 MW during peak load situation. This solution may be applied if economical criteria for transmission planning are applied, more specifically if line construction costs are higher than loss of load costs. Planners have to observe one year period then, not only peak load situation, and take into account annual load duration curves to estimate total amount of undelivered energy and annual loss of load costs.

If the possibility of lines outages is observed also, then probabilistic methods have to be applied in order to estimate annual system operational costs and annual loss of load costs. In economical function several types of costs are included, like:

- loss of load costs,
- production costs,
- cost of network losses,
- re-dispatching costs (if generators re-dispatching may relieve network overloadings), etc.

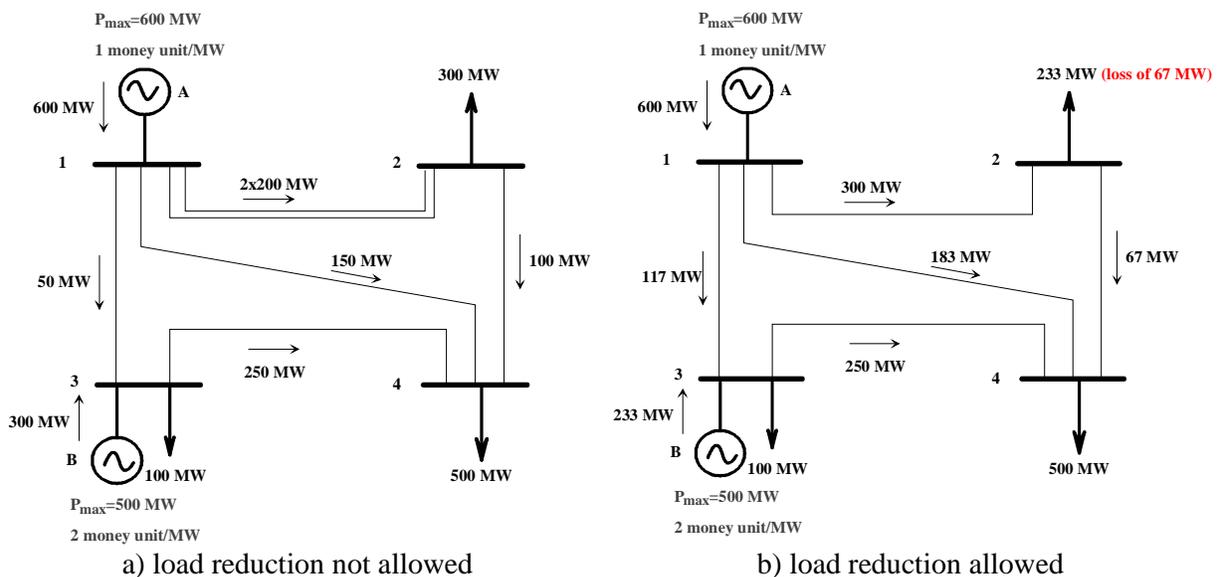


Figure A2 The result of transmission system planning in a vertically integrated company

Let us imagine that Figure A1 presents open electricity market with production companies A and B, and supply companies that supply loads in nodes 2, 3 and 4. They send their bids to market operator who prepares dispatching plan according to minimum production costs, and sent that plan to system operator who is responsible for system operation and security. Electricity price is economically

defined (in the market), and transmission fee is paid for transmission network usage. Consumers may react on high electricity prices and decrease their consumption.

System operator is responsible for transmission network planning, and it estimates that situation presented in Figure A1 will happen in mid-term time horizon if predicted load growth will be achieved and if production companies keep similar bidding behavior like today (fuel prices will remain on the same level, business strategy will not be changed). According to those assumptions system operator plans the investment in line 1-2, it receives approval from regulatory authority and starts the construction as 5 years is minimum necessary time for transmission line construction. Regulatory authority gives its approval to include new line investment costs in transmission fee that is paid by network users (producers, suppliers, or both of them in certain ratio).

Investment decision may be wrong because of different uncertainties which appear in an open electricity market environment. This is illustrated using following examples.

1) *change of production companies bidding behavior*

New line 1-2 is constructed but in the future production companies A and B change their bids. Generator A offers its electricity for 1,5 money unit/MW, and generator B offers its production for 1 money unit/MW. Market operator dispatches generators according to Figure A3.

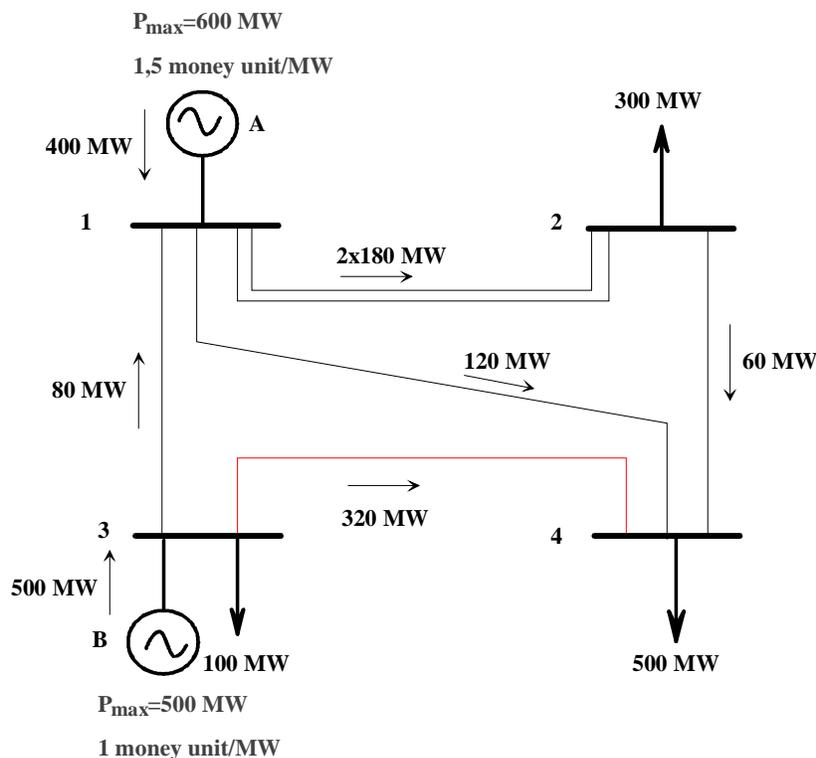


Figure A3 Example of wrong investment because of different bidding behavior

Different generators dispatching will result in completely different power flows in the network. Now line 3-4 is overloaded, and line 1-2 is not jeopardized even if there was only one line between nodes 1 and 2. If system operator had taken into account the possibility of different bidding

behavior it would choose to construct line 1-4 because it solves both problems of possible overloadings of lines 1-2 and 3-4, even if it was two times more expensive than new line 1-2.

2) new power plant (generator) construction

New generator C has been constructed and connected to node 2 (Figure A4) for the situation presented in Figure A1 in mid-time horizon. System operator didn't include this generator into its planning considerations. Generator C has maximum output of 200 MW and production costs 1,5 money unit/MW. Market operator will engage it before more expensive generator B.

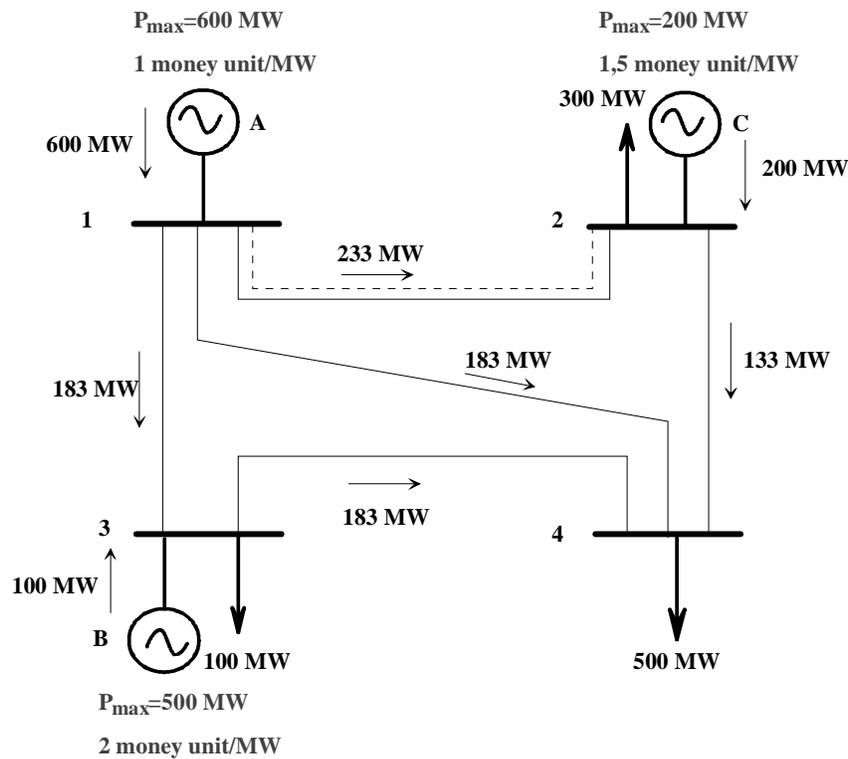


Figure A4 Example of wrong investment because of the new generator construction

In the network where new line 1-2 is out of operation all lines are loaded below their limits. It is obvious that new line 1-2 is unnecessary because network limits were not reached (without taking into account security criterion). Generator C may also have larger costs than generator B, and that leads to Figure A1 (generator C will initially be out of operation because of the highest production costs) and line 1-2 will be overloaded. System operator will notice that and may change dispatch plan to engage generator C with 67 MW (at the same time production of generator B is decreased for 67 MW), and power flows will be as shown in Figure A2-b. Lines loadings are then within limits but overall production costs are higher because generators dispatch is not economically optimal. We say that line 1-2 was congested, and the difference between initial minimum production costs and after re-dispatching production costs is called congestion costs. If system operator takes into account economical criteria during planning process it will compare investment costs and congestion costs (and other types of costs also) and decide whether to construct new line 1-2 or not. We also say that generator C has market power because its engagement is not market oriented only because it is engaged sometime to solve congestion problems in the network. In a

long term this situation is not acceptable from market player’s point of view. If transmission fee is paid according to the post stamp method (transmission price is not dependant on network location) this situation is not visible to generators investors, but if locational marginal prices is applied where electricity price depends on the network location (zones or nodes), higher price in node 2 gives signal to possible generators investors to construct their generators there, and solve network congestion problem at the same time. Otherwise, they may construct generators at node 1 and additionally stress the problem of line 1-2 congestion.

Nevertheless, post stamp method is applied in the SEE today on the national basis (transmission fees are the same inside the area of one TSO responsibility), and electricity price doesn’t depend on the network location.

3) *wrong load growth prediction*

System operator predicted that load in node 2 will rise up to 300 MW for the peak load situation in mid-time horizon and decided to construct new line between node 1 and node 2. Prediction was wrong, and in observed time horizon load has raised up to 200 MW only. Situation is presented in Figure A5.

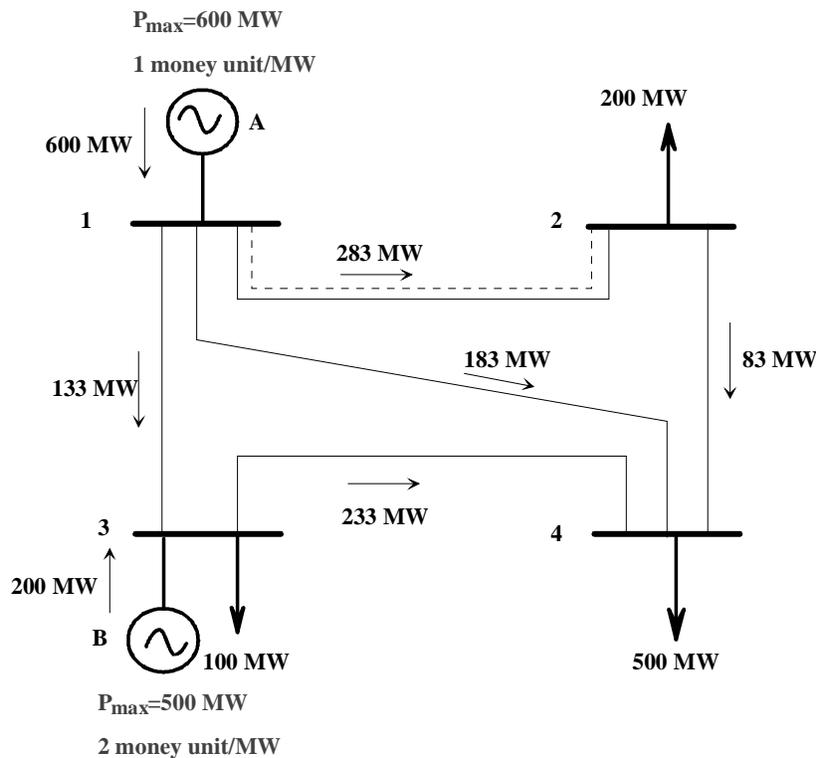


Figure A5 Example of wrong investment because of wrong load growth prediction

With generators market engagement all lines loading are within acceptable limits (without new line 1-2), so there was no need to strengthen the network.

4) *high demand elasticity*

All system operators prediction concerning load growth, generators construction and bidding behavior were correct, but it did not take into account demand elasticity during planning process. Consumers may react on high market prices and reduce their consumption, thus helping in network congestion problem relieving. Situation in Figure A2-b will happen because consumers will possibly decrease their consumption by themselves, and there will be no need for load reduction. System operator may also have special contracts with some consumers connected to node 2 which allow him to disconnect those consumers for certain time period per year. An economical criterion is used, and system operator may decide not to invest in new line 1-2 because it is cheaper to disconnect those specially contracted consumers.

APPENDIX 3: QUESTIONNAIRE

ALBANIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: _____

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. n-1 criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during n-1 operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: _____

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: During winter period is taken the thermal rating for 15 °, otherwise for summer period is taken the thermal ration for 40 °

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and I_{max} 20 minutes)?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network (U_{min} = 99 kV , U_{max} = 121 kV)
- 220 kV network (U_{min} = 198 kV , U_{max} = 245 kV)
- 400 kV network (U_{min} = 380 kV , U_{max} = 420 kV)

12. Do you value the probability of n-1 events?

- no
 yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
 optimum power flows
 probabilistic analysis
 short-circuit calculation
 stability simulations
 others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: Profitability index as the ratio between benefits and costs of some investment

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
 reduction of losses costs,
 reduction of re-dispatching costs,
 reduction of congestion costs,
 benefit from telecommunication lines,
 others (please explain which ones)

Additional comments: _____

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: 0.5 €/kWh

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: We use Sensitive Analyses due to uncertainties data during transmission network planning

BOSNIA AND HERZEGOVINA

1. Who is responsible for transmission network planning in your country?

- TRANSCO/ISO
 Regulatory agency
 others

Additional comments: TRANSCO is responsible transmission network planning, ISO for revision, State Regulatory agency for approval

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: TRANSCO has to prepare one year (detail) and ten (approximate) year plans.

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. *n-1* criterion is related to single loss of following assets?

- single-circuit lines
- double-circuit lines,
- transformers
- generators
- busbars
- others

Additional comments: _____

8. *What events are not allowed to happen during n-1 operational conditions?*

- thermal overloading of branches
- voltage declination below permitted range
- loss of stability
- loss of load
- interruption of power transits
- others

Additional comments: disturbance spreading over power system is not allowed also

9. *Do you have different thermal ratings for lines and transformers during winter and summer period?*

- no
- yes (if yes, please explain the difference)

Additional comments: _____

10. *Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and $I_{max 20 minutes}$?)*

- no
- yes (if yes, please explain the difference)

Additional comments: _____

11. *What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?*

- 110 kV network ($U_{min} = 99$ kV , $U_{max} = 121$ kV)
- 220 kV network ($U_{min} = 198$ kV , $U_{max} = 242$ kV)
- 400 kV network ($U_{min} = 380$ kV , $U_{max} = 420$ kV)

12. *Do you value the probability of n-1 events?*

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
 optimum power flows
 probabilistic analysis
 short-circuit calculation
 stability simulations
 others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: _____

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
 reduction of losses costs,
 reduction of re-dispatching costs,
 reduction of congestion costs,
 benefit from telecommunication lines,
 others (please explain which ones)

Additional comments: Reduction of congestion costs has been used when planning interconnection lines.

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: _____

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
- yes, uncertainties in new power plants size and location
- yes, uncertainties in generators engagement
- yes, uncertainties in hydrological conditions
- yes, uncertainties in existing power plants decommissioning
- yes, uncertainties in load prediction
- yes, uncertainties in branches availability
- yes, uncertainties in regulatory and market issues
- yes, uncertainties in market transactions
- yes, uncertainties in country power balance
- yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
- probabilistic calculations
- other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
- yes (if yes, please explain how)

Additional comments: _____

BULGARIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: _____

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use *n-1* criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. *n-1* criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during *n-1* operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: _____

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and I_{max} 20 minutes)?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min} =$ 99 kV , $U_{\max} =$ 123 kV)
- 220 kV network ($U_{\min} =$ 198 kV , $U_{\max} =$ 245 kV)
- 400 kV network ($U_{\min} =$ 380 kV , $U_{\max} =$ 420 kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: _____

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: 2 EUR/kWh

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: _____

CROATIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: TSO has to prepare 3-years plans and give them to Regulatory agency HERA for approval. Investment costs are included into transmission fee if HERA approves the plans.

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: Status of private or merchant lines has not been solved yet.

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: Grid code defines planning criteria and standards. Some issues are not defined by Grid Code, for example, what if some investment was needed because of n-1 criterion but not satisfy economic criterion at the same time.

6. Do you use *n-1* criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. *n-1* criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during *n-1* operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: disturbance spreading over power system is not allowed also

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and I_{max} 20 minutes)?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min} = 99$ kV , $U_{\max} = 121$ kV)
- 220 kV network ($U_{\min} = 198$ kV , $U_{\max} = 245$ kV)
- 400 kV network ($U_{\min} = 380$ kV , $U_{\max} = 420$ kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: HEP OPS officially doesn't apply economic criteria, but Institute does apply one (profitability index as the ratio between benefits and costs of some investment).

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: Institute calculates first three benefits when applying economic criteria.

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: 2,56 euro/kWh

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: Uncertainties are taken into account through different planning scenarios. Uncertainties in branches availability are taken into account using probabilistic method while applying economic planning criterion.

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: _____

MACEDONIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments:

According to Energy Law, MEPSO prepares 5 year development program (transmission investment plans) and gives them for approval to the Energy Regulatory Commission.

According to Grid Code, MEPSO prepares System Reliability Study for next 10 years and gives it for approval to the Energy Regulatory Commission.

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. n-1 criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during n-1 operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: Cascade switching of elements is not acceptable (disturbance spreading over power system is not allowed).

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and I_{max} 20 minutes)?

- no
 yes (if yes, please explain the difference)

Additional comments: 400 kV OHL has over-current protection relays with 2 step settings:

1st STEP: $I \geq 1760$ A, 1218 MVA, $t = 1200$ sec. trip

2nd STEP: $I \geq 2080$ A, 1440 MVA, $t = 20$ sec. trip

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min} = 99$ kV , $U_{\max} = 121$ kV)
- 220 kV network ($U_{\min} = 200$ kV , $U_{\max} = 240$ kV)
- 400 kV network ($U_{\min} = 380$ kV , $U_{\max} = 420$ kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments:

When solving specific problems during planning phase, from set of technically acceptable options, solution is selected by applying economic criterion (NPV method).

In feasibility studies for investigating new interconnection projects, comprehensive cost-benefit analyses are done.

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: When investigating solutions for local (internal) problem, simple NPV method is applied, taking into account reduction in active losses and difference in operational and maintenance costs.

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
- between 1 and 3 euro/kWh
- more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: _____

18. Do you have some additional planning criteria for interconnection lines?

- no
- yes (please, explain which ones)

Additional comments: In recent feasibility investigations of new interconnections, SDDP software is used, which gives overall change in system operational costs derived by different interconnection options and different working regimes of power systems (isolated or coordinated operation and development).

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
- yes, uncertainties in new power plants size and location
- yes, uncertainties in generators engagement
- yes, uncertainties in hydrological conditions
- yes, uncertainties in existing power plants decommissioning
- yes, uncertainties in load prediction
- yes, uncertainties in branches availability
- yes, uncertainties in regulatory and market issues
- yes, uncertainties in market transactions
- yes, uncertainties in country power balance
- yes, other uncertainties (please explain which ones)

Additional comments: _____

20. *If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?*

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. *Do you estimate a risk of wrong transmission investments?*

- no
 yes (if yes, please explain how)

Additional comments: _____

MONTENEGRO

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: _____

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: In future transmission investments will be financed through transmission fee approved by Regulatory Agency _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. n-1 criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during n-1 operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: _____

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: Low temperatures during winter allow higher thermal ratings

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and $I_{max 20 minutes}$?)

- no
 yes (if yes, please explain the difference)

Additional comments: During interrupted operational conditions overloading of elements above thermal rating is allowed for 20 minutes according to it's specifications

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min}=104.5$ kV , $U_{\max}=115.5$ kV)
- 220 kV network ($U_{\min}=198$ kV , $U_{\max}=242$ kV)
- 400 kV network ($U_{\min}=360$ kV , $U_{\max}=440$ kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: n-2 criterion is also used for transmission network planning

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: Economic criteria is not applied

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: 0 euro/kWh

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: Interconnection lines are planned on regional level

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: In future, Regulatory Agency will assess risk of wrong transmission investments

ROMANIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: TSO has to prepare a transmission development plan for 10
years. These plans are updated each 2 years.

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: The investments directly related to the grid access are paid by the
solicitors(Consumers or Generators)

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: Additional to the grid code there is a standard with several procedural and
technical details: PE026/1995 -Standard for the Romanian power system design

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. n-1 criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: The "N-2" criterion is utilized to dimension transmission capacity for the Nuclear Power Plant.

8. What events are not allowed to happen during n-1 operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: Tripping of the other installations through the protective devices of the equipment which are not directly affected by the disturbance.

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: Different thermal ratings are used only for operational purposes.

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and $I_{max 20\text{ minutes}}$?)

- no
 yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min}=99$, $U_{\max}=123$ kV)
- 220 kV network ($U_{\min}=198$ kV , $U_{\max}=242$ kV)
- 400 kV network ($U_{\min}=380$ kV , $U_{\max}=420$ kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: In the long term plans the reliability indicators are assumed for each substation

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: - Static and Dynamic stability
- Technical criteria to dimension the reactive power compensation installations

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: Economic Analysis

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: 1) the efficiency of the short and medium term investments in TN has to be justified in the planning stage, using at least the payback time criteria.

2) The TN long-run planning studies (10years) have to offer hierarchical development solutions based on economic criteria.

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: All the possible benefits are taken into account

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: 0.8 euro/kWh

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: _____

SERBIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: TSO has to prepare one year and five year plans and give them to Regulatory agency for approval.

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. *n-1* criterion is related to single loss of following assets?

- single-circuit lines
- double-circuit lines,
- transformers
- generators
- busbars
- others

Additional comments: _____

8. What events are not allowed to happen during *n-1* operational conditions?

- thermal overloading of branches
- voltage declination below permitted range
- loss of stability
- loss of load
- interruption of power transits
- others

Additional comments: disturbance spreading over power system is not allowed also

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
- yes (if yes, please explain the difference)

Additional comments: There is different tuning of overcurrent protection during winter and summer period

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and $I_{max 20 minutes}$?)

- no
- yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{min} = 99$ kV , $U_{max} = 121$ kV)
- 220 kV network ($U_{min} = 198$ kV , $U_{max} = 242$ kV)
- 400 kV network ($U_{min} = 380$ kV , $U_{max} = 420$ kV)

12. Do you value the probability of *n-1* events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
 optimum power flows
 probabilistic analysis
 short-circuit calculation
 stability simulations
 others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: Profitability index as the ratio between benefits and costs of some investment.

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
 reduction of losses costs,
 reduction of re-dispatching costs,
 reduction of congestion costs,
 benefit from telecommunication lines,
 others (please explain which ones)

Additional comments: Reduction of congestion costs has been used when planning interconnection lines.

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: _____

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: Difference of energy prices

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: _____

UNMIK

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: _____

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. n-1 criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during n-1 operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: _____

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: During winter period is taken the thermal rating for 15 °, otherwise for summer period is taken the thermal ration for 40 °

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and I_{max} 20 minutes)?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min} = 99$ kV , $U_{\max} = 121$ kV)
- 220 kV network ($U_{\min} = 198$ kV , $U_{\max} = 245$ kV)
- 400 kV network ($U_{\min} = 380$ kV , $U_{\max} = 420$ kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: Profitability index as the ratio between benefits and costs of some investment

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: _____

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: 0.4 €/kWh

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: We use Sensitive Analyses due to uncertainties data during transmission network planning

SLOVENIA

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: _____

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: _____

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: _____

6. Do you use *n-1* criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. *n-1* criterion is related to single loss of following assets?

- single-circuit lines
 double-circuit lines,
 transformers
 generators
 busbars
 others

Additional comments: _____

8. What events are not allowed to happen during *n-1* operational conditions?

- thermal overloading of branches
 voltage declination below permitted range
 loss of stability
 loss of load
 interruption of power transits
 others

Additional comments: _____

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
 yes (if yes, please explain the difference)

Additional comments: _____

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and $I_{max 20\text{ minutes}}$?)

- no
 yes (if yes, please explain the difference)

Additional comments: During interrupted operational conditions overloading of elements above thermal rating is allowed for 20 minutes according to it's specifications

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

- 110 kV network ($U_{\min}=104.5$ kV , $U_{\max}=123$ kV)
- 220 kV network ($U_{\min}=220$ kV , $U_{\max}=245$ kV)
- 400 kV network ($U_{\min}=380$ kV , $U_{\max}=420$ kV)

12. Do you value the probability of n-1 events?

- no
- yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
- optimum power flows
- probabilistic analysis
- short-circuit calculation
- stability simulations
- others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
- yes (if yes, please explain which one)

Additional comments: _____

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
- reduction of losses costs,
- reduction of re-dispatching costs,
- reduction of congestion costs,
- benefit from telecommunication lines,
- others (please explain which ones)

Additional comments: Economic criteria is not applied

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: _____

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: _____

TURKEY

1. Who is responsible for transmission network planning in your country?

- TSO/ISO
 Regulatory agency
 others

Additional comments: _____

2. Are you obliged to prepare different transmission network investment plans by law?

- no
 yes, short-term plans
 yes, mid-term plans
 yes, long-term plans

Additional comments: Under the law TEIAS is the owner of the HV and EHV network and also responsible for planning construction operation and maintenance of transmission system. Therefore TEIAS prepares the “Transmission System Investment Plan” and additionally the “Ten Years Statement Report” for the development of the transmission system in ten years period.

3. Is Regulatory Agency obliged to give its approval on transmission network development plans?

- no
 yes

Additional comments: “Ten Years Statement Report” is submitted to the EMRA which makes the final proposal.

4. How transmission investments are financed in your country?

- through transmission fee
 by loans
 by internal TSO financial sources
 by private investors

Additional comments: _____

5. Do you have official document related to transmission network planning with defined planning criteria?

- no
 yes, grid code
 yes, other document(s)

Additional comments: “System Security and the Quality of Supply Document”

6. Do you use n-1 criterion for transmission network planning?

- no
 yes

Additional comments: _____

7. *n-1* criterion is related to single loss of following assets?

- single-circuit lines
- double-circuit lines,
- transformers
- generators
- busbars
- others

Additional comments: Details are given in “System Security and the Quality of Supply Document”

8. What events are not allowed to happen during *n-1* operational conditions?

- thermal overloading of branches
- voltage declination below permitted range
- loss of stability
- loss of load
- interruption of power transits
- others

Additional comments: _____

9. Do you have different thermal ratings for lines and transformers during winter and summer period?

- no
- yes (if yes, please explain the difference)

Additional comments: During winter period is taken the thermal rating for 25° , for summer and minimum (spring) period is taken the thermal ratio for 40° details are given in “System Security and the Quality of Supply Document”

10. Do you have different thermal ratings for lines and transformers during normal and interrupted operational conditions (for example different I_{max} and I_{max} 20 minutes)?

- no
- yes (if yes, please explain the difference)

Additional comments: _____

11. What is permitted voltage range in your country in 110 kV, 220 kV and 400 kV networks?

For Turkish Power Transmission System we have 3 nominal voltage levels these are; 380 kV, 154 kV and 66 kV. For planning standarts;

- 380 kV network (U_{min} = 370 kV , U_{max} = 420 kV)
- 154 kV network (U_{min} = 146 kV , U_{max} = 162 kV)
- 66 kV network (U_{min} = 62 kV , U_{max} = 70 kV)

12. Do you value the probability of n-1 events?

- no
 yes (if yes, please explain how do you value the difference)

Additional comments: _____

13. Do you have some other technical criteria defined for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: _____

14. What kind of analyses do you perform for transmission network planning?

- load-flow, security analysis
 optimum power flows
 probabilistic analysis
 short-circuit calculation
 stability simulations
 others (please, explain which ones)

Additional comments: _____

15. Do you apply economic criteria for transmission network planning?

- no
 yes (if yes, please explain which one)

Additional comments: _____

16. If you apply economic criteria for transmission network planning, what kind of benefits do you estimate?

- reduction of loss of load costs,
 reduction of losses costs,
 reduction of re-dispatching costs,
 reduction of congestion costs,
 benefit from telecommunication lines,
 others (please explain which ones)

Additional comments: _____

17. What's the value of undelivered energy (loss of load) costs per kWh in your country?

- less than 1 euro/kWh
 between 1 and 3 euro/kWh
 more than 3 euro/kWh,

Please note the exact value of undelivered energy costs: _____

18. Do you have some additional planning criteria for interconnection lines?

- no
 yes (please, explain which ones)

Additional comments: _____

19. Do you take into account uncertainties during transmission network planning and which ones?

- no
 yes, uncertainties in new power plants size and location
 yes, uncertainties in generators engagement
 yes, uncertainties in hydrological conditions
 yes, uncertainties in existing power plants decommissioning
 yes, uncertainties in load prediction
 yes, uncertainties in branches availability
 yes, uncertainties in regulatory and market issues
 yes, uncertainties in market transactions
 yes, uncertainties in country power balance
 yes, other uncertainties (please explain which ones)

Additional comments: _____

20. If you take into account uncertainties during transmission network planning what kind of approach do you use for modeling?

- multi-scenario analyses
 probabilistic calculations
 other methods (please explain which ones?)

Additional comments: _____

21. Do you estimate a risk of wrong transmission investments?

- no
 yes (if yes, please explain how)

Additional comments: _____

APPENDIX 4: PLANNING SCENARIOS

Short-term planning

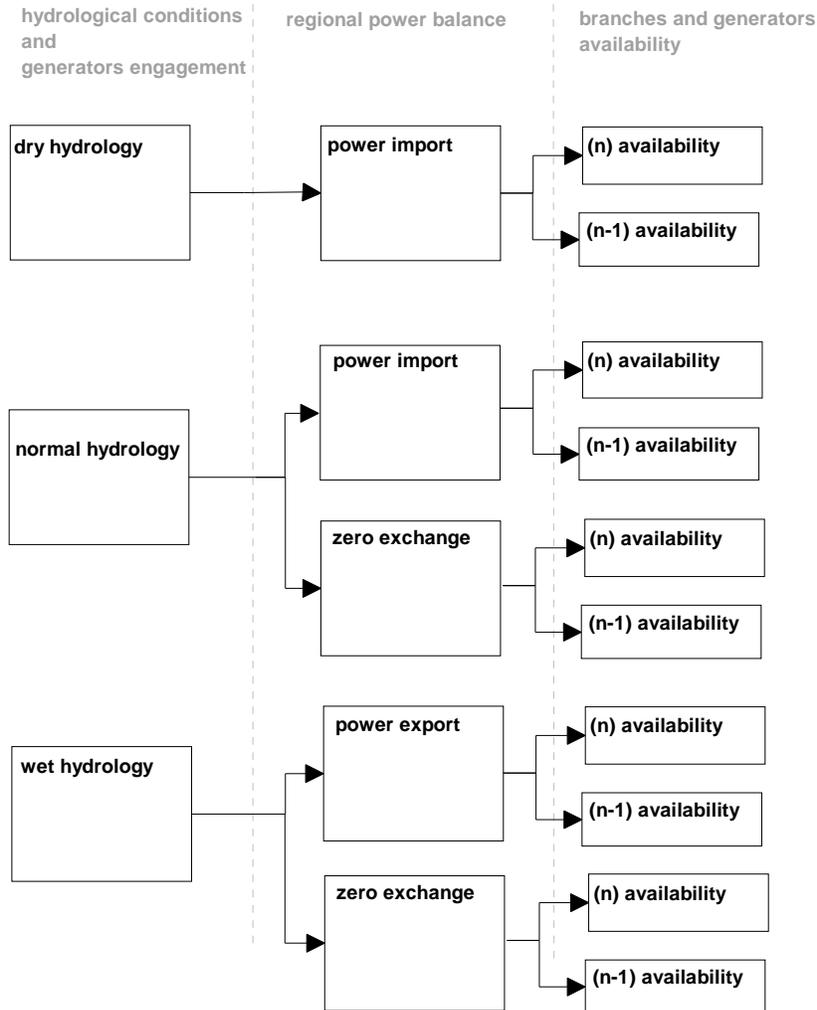


Figure A6 Short-term planning scenarios

Mid-term planning

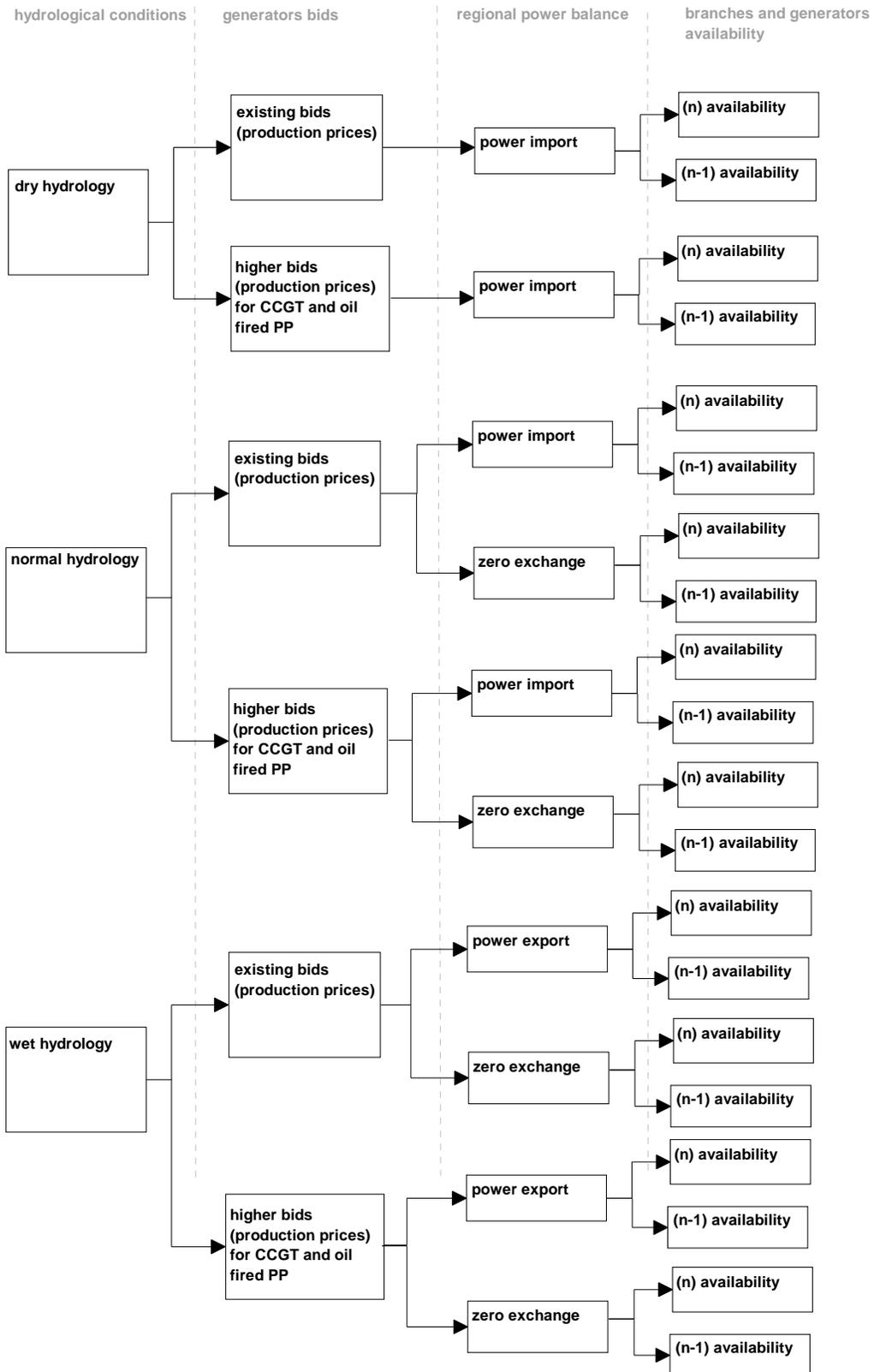


Figure A7 Mid-term planning scenarios

Long-term planning - part 1

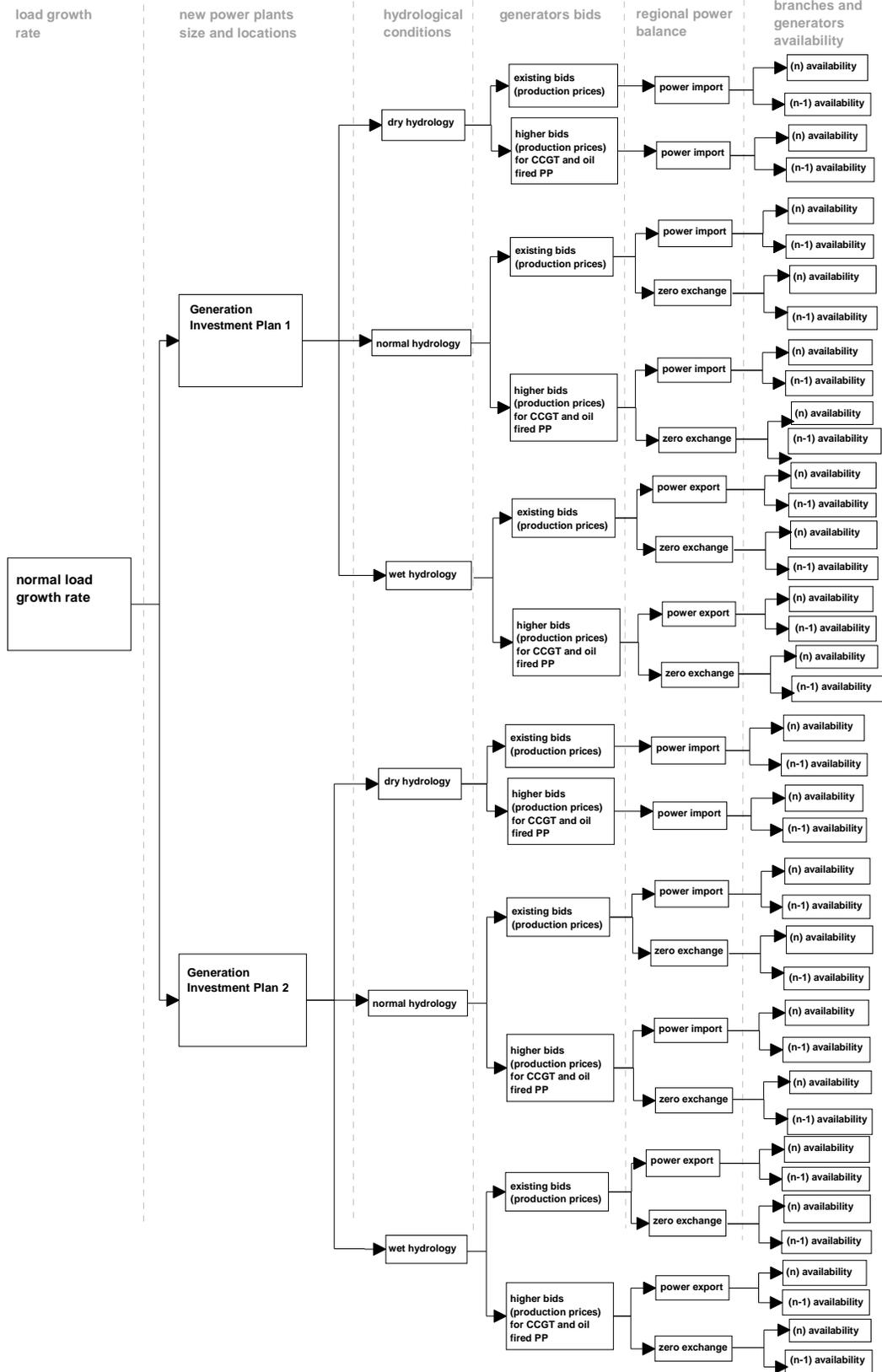


Figure A8 Long-term planning scenarios – part 1

Long-term planning - part 2

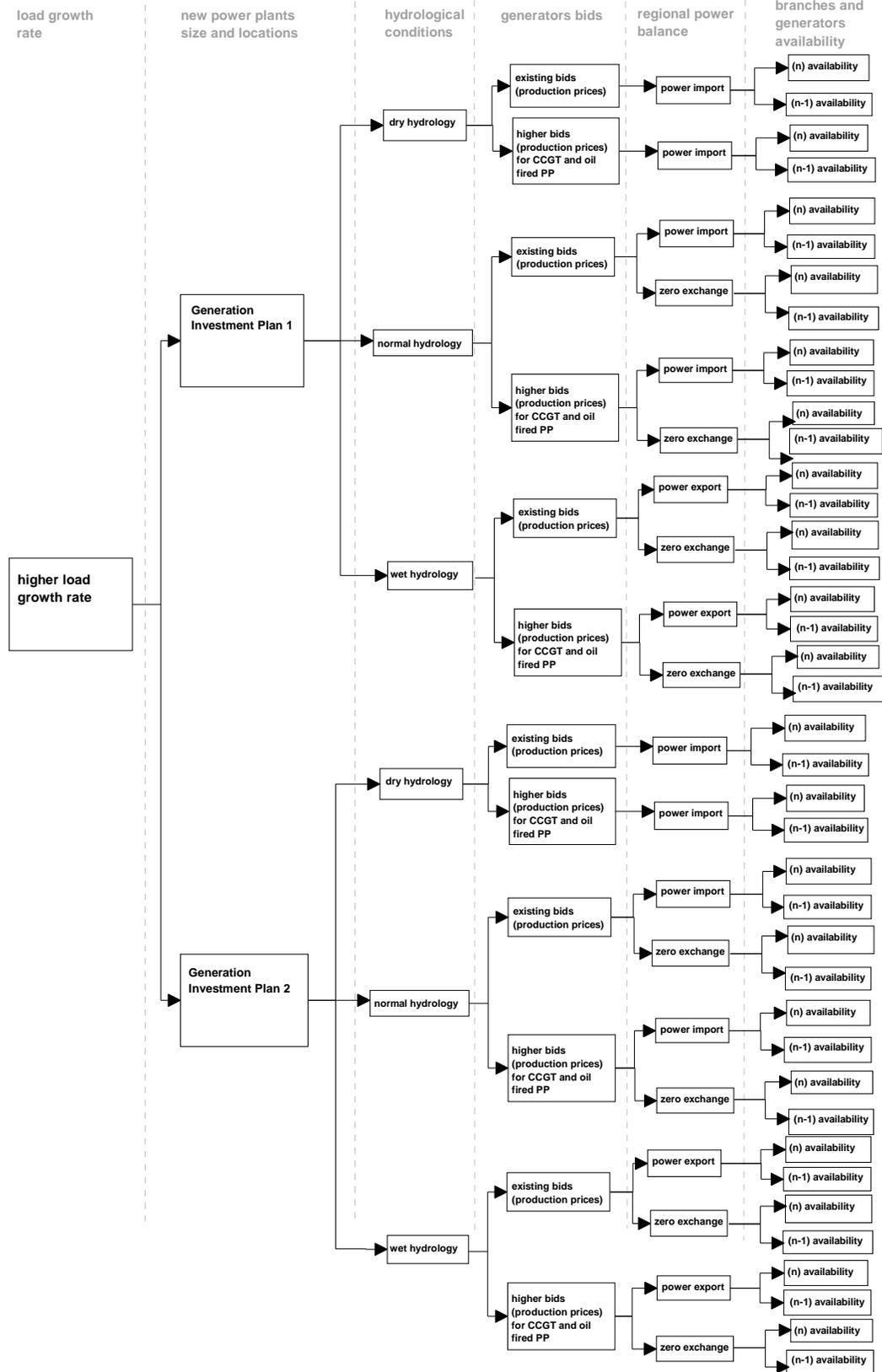


Figure A9 Long-term planning scenarios – part 2