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NETWORK PLANNING IN A DEREGULATED ENVIRONMENT

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Executive summary

In January 2000 the CIGRÉ Study Committee 37 (SC37) launched the work of WG37-30 with the title of “Network Planning in a Deregulated Environment”. The inspiration for establishing the working group was experiences from several countries with the market and environment placing new and heavy demands and uncertainties on the transmission grid.

The work started in May 2000 with fourteen participants representing seventeen different areas. Eleven of these areas were European, six areas were from Australia/New Zealand and one from Qatar.

The greatest interest in the work has been among the European countries. This is shown among the composition of the working group members. Furthermore, a large part of European countries did reply to worldwide enquiries. A consequence is that the content of the work may be marked by the European experiences and concerns, even though other experiences are included.

The report can be seen as a “first step” towards a new planning approach. It discusses *the most important key issues* and may give inspiration to set up a revised planning approach under liberalised conditions.

Background and purpose

The introduction of the electricity market has resulted in new frames and considerations in transmission network planning. As more and more countries are liberalising the electricity sector, a number of questions have been raised regarding the transmission network planning e.g. does the market opening require grid reinforcements and can the market requirements be an argument for the reinforcement?

On the other hand new economic frames may demand transparency and perhaps increased utilisation of the existing grid which again may jeopardise the system reliability. As a consequence a crucial question is whether the planning criteria should be relaxed, tightened or remain unchanged with the introduction of the open electricity market.

At the same time transmission system planners see the fundamentals change dramatically, especially fundamentals about generation capacity. International markets are (and will be) established, and therefore, interconnections play an important role in the market.

The overall objective of the study is to analyse the need for development of the medium- and long-term transmission planning approach in deregulated surroundings. This includes identification and analysis of the changing conditions and the key issues determining the system reliability and need for transmission capacity.

Also the planners' possibilities of gathering the relevant data, including managing confidential information belonging to the market players, and managing the demand for publicity was the purpose of the work. This has not been analysed in detail, but the resulting difficulties related to transmission planning are included.

Liberalisation

Different approaches to achieve the liberalisation and to operate the market are chosen and different levels of liberalisation are achieved or desired. Liberalisation may be implemented through de-regulation, which means no regulation at all from a governmental body or another regulator. In most cases a need for re-regulation has been recognised i.e. a changed regulation which to a limited extent promotes the competition.

In the case of re-regulation the government or another regulator set up frameworks and demands limiting the competition for instance under consideration of the economics, the environment and the system reliability. Most areas are re-regulated, and it has proved important to maintain some regulation in order to ensure the economy, the obligations of the parties, the environment and the system reliability in liberalised surroundings.

Methods for identification of key issues

Three different methods were used for identification of the most important key issues in the network planning. These were a questionnaire study, case studies and descriptions of the existing planning approaches.

Through the questionnaire study the experiences and expectations from twenty-one areas all over the world were analysed. The answers cover eleven areas from Europe and ten from other areas. They have different experiences (zero to fifteen years) in liberalisation.

The questionnaire contains questions regarding the planning approach which include the fundamentals, the contingency and decision criteria and the way uncertainties are included in the planning. The results of the *questionnaire* are aimed at the present situation more than the expectations to the future.

The average result from the questionnaire represents an area with one to five years of liberalisation and a public, fully independent Transmission System Operator (TSO) that owns the entire transmission network. An independent public authority regulates the TSO, and the transmission business income is regulated. The TSO has to comply with rules governing transmission grid access and offer terms for access to the transmission grid. The primary activities for the TSO are network planning, system operation, maintenance and construction of transmission grids.

Nine *case studies* were prepared in the working group covering four areas. They describe existing or former problems in relation to the network planning, their consequences and the actions taken.

Descriptions of *the present planning approach* were prepared for the areas covered by the working group. The descriptions contain information about technical and economical methods to detect the need for reinforcements, possible solutions and methods to make the final decision.

The methods used for identification of key issues complement each other. The questionnaire and the description of the planning approaches are more likely to identify the key issues. The case studies may also inspire to solutions to the existing and coming problems in transmission network planning.

Definition of transmission

Traditionally the power system grid has been divided into the main transmission grid and the underlying distribution grid. Several reasons for distinguishing between transmission and distribution exist, including the grids may have different ownership and different technical functions. As the generating capacity typically is connected to the main grid they may also operate under different demands for reliability.

A number of definitions of the *term transmission* exist, which addresses its main functions and/or a quantitative categorisation typically based on the voltage level. The different definitions have shown a need for an update of the existing CIGRÉ definition. A new definition is proposed including the functions of power transfer, imports and exports and support to higher voltage levels:

"The function of transmission is the transfer of electrical energy/power in bulk from generation or import sources to a main point of supply or export sources, the provision and transport of ancillary services and support to higher voltage levels.

These functions include transfer of electrical energy/power between electricity grids or control areas, and power support through interconnections and between generating units"

On this functional definition each area can specify an appropriate quantitative definition based on the voltage levels.

Planning horizon

Traditionally, different time frames are used in network planning, with different degrees of detail and with the use of different tools and models. Network planning is a process which typically may be broken down into the following stages

- long-term studies which are characterised by a high degree of uncertainty as the planning horizon may be up to twenty years.
- medium-term studies where the uncertainties are reduced as the planning horizon may be up to ten years.
- short-term studies where the uncertainties are even more reduced as the planning horizon may be up to five years.

The medium- and long-term planning is in focus in this report, but even the short-term horizon is important due to uncertainties.

Changing conditions for network planning

The success of planning the future transmission grid depends on the ability to forecast the fundamentals for the network planning. The fundamentals are highly dependent of the socio-development and the legislation.

The primary changing condition is the introduction of the international electricity markets including the unbundling of generation and grid and the introduction of competition among the generation companies. Typically, power systems are not entirely liberalised, but re-regulated as the system security, the efficiency and the environment are considered as well as the function of the electricity market. This may lead to an opaque market function.

The international environmental considerations have led to an increasing amount of Renewable Energy Sources (RES) which are especially challenging both in relation to the operation of the system and to the market structure (RES certificates or the like). The public opposition against the visual impact from overhead lines and economic frames also influence the possibility of building new transmission lines.

Identification of key issues

A number of key issues have been listed and classified as the most important due to the changed conditions. An overall key issue is establishing the long-term *fundamentals* for the planning. The most important ones are

- uncertainties in electricity prices (market prices).
- uncertainties in regulation and transmission pricing.
- possibility of financing new interconnections.
- uncertainties in development in international markets.

These uncertainties call for a new planning approach.

The information about the generating capacity has become more uncertain as a consequence of the changing conditions. The unbundling and confidentiality policies have led to some information becoming unavailable for the transmission grid planner. Due to the generation companies' reaction on price signals this new element, hard to predict, has been introduced. The most important *key issues on generation* are uncertainty in

- predicting the establishment of new generating capacity, including the question of when and how much due to uncertainties in market prices.
- predicting the placement of new generating capacity and the dispatch.
- predicting the decommissioning of old generation capacity.
- future generation data due to confidentiality policies.

Also the prediction of power consumption will depend on the consumers' reaction on price signals (elasticity). This uncertainty is considered minimal in relation to other uncertainties.

The markets will become international and the international perspective will be in focus. The frameworks for the exchange on interconnections have changed and they are now (or will be) dependent on the difference in the electricity prices in the interconnected areas. The most important *key issues on interconnections* are

- changing transport patterns on interconnections and consequently in the internal grid due to reactions on price signals.
- the need for international coordinated planning.
- ensuring the financing of new interconnections and the belonging internal grid.

Regulation may introduce new uncertainties and the most important key issues on that condition are

- environmental regulation leading to an increasing amount of RES generation with prioritised grid access. This is limiting the market function and makes the generation data even more uncertain.
- income regulation not coordinated with the need for transmission capacity may limit the possibilities of establishing new transmission lines. This result in new demands on the existing grid or in limitations on the market function.
- regulation through procedures of approval may delay new transmission lines resulting in new demands on the existing ones or limitations on the market function.

Another key issue influencing the planning approach not directly a consequence of the liberalisation is the increasing amount of non-dispatchable generation. Especially the wind power introduces new demands for ancillary services from the dispatchable generation and interconnections.

It is important that the planning criteria are applicable together with the changing conditions and the long-term fundamentals. As a consequence the most important key issues are, whether

- the existing contingency criteria need an update (relaxation or strengthening).
- there is a need for supplemental criteria (economic and performance).

Analysis of the planning approach

Typically the transmission network planning approach includes a set of fundamentals, some realistic events, under which the system must be able to operate and specified consequences that are accepted under the operation. These basic elements are still reasonable to consider.

In liberalised surrounding marginal costs for generators, price elasticity of consumers and market players' estimates of future power prices will be important together with rules for access to the capacity on the interconnections.

It is necessary to plan with interconnections, including economic rationales in determination of the exchange and the need of reinforcements. The planning must also be done in close co-operation with the neighbouring areas both on reliability and the financing of reinforcements.

In some areas the practical implementation of new transmission lines has become difficult because of income regulation which affects the ability to invest. Difficulties related to planning and consents and public opposition against overhead lines have also been introduced.

The *planning fundamentals* have changed dramatically. In order to ensure the generation fundamentals related to the players in the market the following initiatives may be possible.

- The system operator develops models for predicting the generation capacity and the generation dispatch including the system reliability, the marginal costs for generation, the future electricity price and the future environmental policy. The key problem is the prediction of the electricity price. Scenarios may be needed for this purpose.

- The generation companies can deliver the long-term estimates in generation data to the system operator. This may be difficult because of the need for confidentiality in a competitive environment.
- The system operator uses different scenarios in capacity development and generation dispatch for development of a flexible transmission grid structure.

Because of the long lead times for establishing transmission lines in relation to establishment of generation it is considered important that the system operator continues to perform medium- and long-term planning as well as short-term planning.

In order to ensure relevant generation fundamentals for network planning public and transparent regulation is needed. This may ease the access to generation data for network planning.

The possibility and need for reducing the contingency criteria, depends on the actual system. In a historic conservative planned system the potential for operating the system under harder conditions may be accepted e.g. with introduction of electronic devices.

No immediate need for changing *the contingency criteria* seems to be necessary, but there may be a need for

- supplementing with planning criteria for the utilisation of the interconnections.
- expanding with criteria for the system performance.
- expanding with economic criteria for reinforcement of interconnections.

With greater emphasis put on the economic rationales (the inclusion of cost benefit) in the decision criteria it may be included in the planning practice.

The inclusion of economic rationales and performance indices will also include the introduction of new economic models and probabilistic analysis methods for network planning.

Future work

As this analysis is the "first step" in developing a new planning approach to the transmission network further work will be needed.

The working group has identified a lot of issues that need to be addressed, but does not recommend the establishment of a new working group. Instead, the group recommend that relevant issues are treated in C1 at future CIGRÉ sessions through preferential subjects.

The most important conclusions leading to the future work are summarised:

- The use of scenarios in the planning approach is a necessary tool to handle uncertainties in the fundamentals.
- International considerations regarding the market and environment are crucial in laying down the fundamentals.
- The contingency criteria have to be harmonised on interconnections.
- Measures of system reliability are important in order to lay down technical performance of the system.
- There is a need to integrate economical parameters in the decision process
- There is a need for planning methods which integrate the technical and economic performance of the system (e.g. probabilistic methods)

The future work includes a specification of how to address the uncertainties by using scenarios. An important task in that connection is to describe the procedure of performing scenario analyses. For this task international considerations are crucial.

As transmission network planning still are based on reliability issues it is an important future task to identify the relevant measures and levels of reliability in liberalised surroundings.

Furthermore, analysis methods for transmission network planning including considerations for transport and access to ancillary services will be necessary to develop (especially for areas with a large amount of non-dispatchable generation). Also finding/developing economic methods, including the market aspects are future tasks.
Methods for analysing transmission grids must include the economical perspective in a transparent way. This task has been started for instance the discussion of transmission prising during Cigré session 2000.

Work regarding coordinated criteria for building and financing of interconnections and the belonging internal transmission capacity would be an advantage for interconnected areas.

1. Introduction

The transition from monopoly to an open electricity market is a global process, which has been going on for several years. In an overall perspective the open electricity market means liberalising the sector to create competition in power generation and supply.

Restructuring the electricity industry is a natural consequence of the liberalisation; for instance the network operations and the generation have been unbundled. Furthermore, a non-discriminative open access for the producers and consumers to the distribution and transmission systems has been created.

When moving from a bundled electricity system with a controllable and well-defined production capacity to surroundings with competition the framework for the network planning will change. The network must now also meet market requirements.

The purpose

The introduction of the electricity market has resulted in new frames and considerations in transmission network planning. As more and more countries are liberalising the electricity sector a number of questions have been raised regarding transmission network planning e.g. does the market opening require network expansions and can the market requirements be an argument for the expansion?

On the other hand new economic frames may increase pressure on utilisation of the existing network which again may jeopardise the system reliability. As a consequence it is a crucial question whether the planning criteria should be relaxed, be tightened or stay unchanged with the introduction of the open electricity market.

At the same time transmission system planners see fundamentals change dramatically especially in relation to production capacity. International markets are established and therefore interconnections play an important role.

The purpose of this work is to re-evaluate the network planning approach after the electricity sector has been liberalised. Participants in the working group have been representatives from several transmission system operators (TSO), independent system operators (ISO) and organisations, enclosure 1, page 2.

Liberalisation

Different approaches to achieve liberalisation and to operate the market have been chosen with different levels of liberalisation achieved or desired. Liberalisation may be implemented through de-regulation, which means no regulation at all from a governmental body or another regulator. In most cases there has been recognised a need for re-regulation, i.e. changed regulation, which to a limited extent promote the competition.

In the case of re-regulation the government or another regulator set up frameworks and demands limiting the competition for instance under consideration of economics, the environment and system reliability. Most areas are re-regulated, and it has proved important to maintain some regulation in order to ensure economic development, obligations of the parties, environmental considerations, and the system reliability in liberalised surroundings.

This work does not only concern areas which are de-regulated, but all areas with an open electricity market, achieved either through de-regulation or re-regulation. Therefore, in this context the term liberalised is used in order to include all these areas.

Experiences with liberalisation vary considerably between the different countries, as some have been liberalised for 10-15 years and others may still be monopolies. Many countries are in the incipient phase of the process, having been liberalised for less than five years.

The challenge

Basically the power system has to ensure system reliability, i.e. adequacy and security. In order to do that the network must be developed in line with the social development and with a liberalised electricity sector the function of the market is crucial when determining the planning fundamentals.

Due to the competition the future production capacity will become more uncertain and the unbundling of generation and network operations means that the network planner does not have the same access to generation information. This means that it becomes more difficult to set up the generation fundamentals to be used in network planning.

As more and more areas are liberalised, national areas of power supply become a part of international markets. This means that each area can not be operated and planned separately, because trading across interconnections effect the supply and demand globally. Therefore, network planning also has to be seen in an international perspective.

Furthermore it seems in general difficult to get permission to built new over head lines. This is due to fear of magnetic field exposure, visual impact, and difficulties for the network planners to prove the need for new network. The latter is a result of the surroundings changing and of the fundamentals in planning not changing correspondingly.

Other environmental considerations lead to large amounts of Renewable Energy Sources (RES), which may be prioritized above other technologies and which may be unpredictable generation. This also effects the planning approach.

It is a different task to perform network planning in liberalised surroundings from a monopoly, due to lack of information about the production machinery, uncertainties in the market developments and the obligations both to the consumers and the market players. Furthermore environmental issues are expected to make an important impact on the future planning approach.

2. Methods for identification of key issues

As a consequence of the liberalisation of the electricity sector a re-evaluation of the transmission network planning approach has proved necessary.

The overall objective according to the Terms of Reference, enclosure 1, is to analyse the need for development of medium- and long-term transmission planning methods in liberalised surroundings. The work includes a re-evaluation of the planning fundamentals (production, consumption, and exchange), the planning criteria (technical/economic) and the analysis methods (deterministic/probabilistic, technical/economic).

In order to re-evaluate the planning approach it is necessary to identify and analyse the changing conditions in relation to the surroundings, i.e. primarily how the introduction of the market, and secondly how the consideration for the environment effect the planning approach.

In this context the key issues which determine the need for transmission capacity must be identified and analysed including an examination of the grid planners' possibilities of gathering the relevant data. The key issues are the expected or experienced difficulties in network planning due to the changed conditions.

The analysis of the changing conditions and the key issues is made from a technical point of view without going into detail with the market organisation and legal frames.

Questionnaire

Through a questionnaire study the experience and expectations from different geographical areas were analysed with regard to identification of new relevant key issues, **appendix 1**. The questionnaire covers answers from 21 areas of which 11 were European and 10 were from other parts of the world.

The questionnaire contains questions regarding the planning approach which include the fundamentals, the contingency and decision criteria, and how uncertainties are included in planning. The results of the questionnaire are aimed at the present situation more than the expectations of the future.

Case studies

Furthermore, case studies prepared in the working group were analysed, see **enclosure 2**. They describe existing or former problems in relation to the network planning, their consequences and the actions taken. The case studies also describe potential future issues and how these problems may be solved.

The members of the working group also provided a description of the present planning approach in their area, **appendix 2**, with information about how to detect the need for reinforcements, solutions and how to make the final decision.

All methods complement each other. The questionnaire and the description of the planning approaches are more likely to identify the key issues, and the case studies may supply key issues and provide inspiration for solutions.

The work considers the medium- and long-term planning of the transmission grid. This means that the problems of the short-term network planning in the transition from monopoly to an open electricity market are not considered. Neither is the planning of the distribution grid.

Definitions

The definition of the transmission grid and the long- and medium-term planning are not unambiguous. With the CIGRÉ glossary, ref. [1], as a starting point and answers from the questionnaire the terms transmission (**enclosure 3**) and medium- and long-term planning (**enclosure 4**) are defined from a functional point of view.

3. Definition of transmission

Traditionally, the power system has been divided into the underlying distribution grid and the main transmission grid. There are several reasons for distinguishing between transmission and distribution, the main ones being that the grids have different ownership and different functions, as the generating capacity typically is connected to the main grid, and that they operate under different demands for reliability. This effects the planning approach and operation of the grids.

As this work concerns the transmission network planning, a common understanding of the function of transmission is important. This includes the need for differentiating between transmission and distribution.

As far as the transmission grid concerns, a number of different definitions exist which address its main functions and/or a quantitative categorisation typically based on the voltage level. These definitions may come from both technical bodies and from national legislation. Different definitions of the transmission grid are presented in **enclosure 3**, based on the answers from the questionnaire analysis (Appendix 1) and definitions from other international organisations and companies. In most areas the definition did not change due to the liberalisation.

The definition of the transmission grid as a part of this report is as a starting point the CIGRÉ definition, which is a functional definition, ref. [1]:

"The function of transmission is the transfer of electrical energy in bulk from generation or import sources to the distribution level and to reduce the investment in generating capacity. This function also includes transfer of electrical energy between electricity grids or control areas".

The large number of other definitions indicates a need for analysing whether the CIGRÉ definition is sufficient to cover the different points of view and to cover the development from a monopoly to liberalised surroundings. In relation to this task, the following questions are discussed:

- The need for a conceptual differentiation between transmission and distribution.
- The need for functional and quantitative definitions.
- Which criteria to include in the definitions.

3.1 The conceptual differentiation

The overall function of the transmission grid is the *transfer* of energy, while the underlying grids *distribute* the energy. The differences in *transferring* and *distributing* are mainly the amount of energy to be transported and the distance of transportation. When energy is transferred, it is typically large amounts over large distances, while the distribution of energy typically is smaller amounts over smaller distances.

The demand for reliability in relation to the transmission grid concerns the ability of transferring the adequate amount of energy to the distribution grid and the ability of transferring ancillary services. In this context, the ancillary services concerns the reactive power and frequency control.

The demand for reliability in relation to the distribution grid concerns the ability to distribute an adequate amount of energy to the consumer.

3.2 Functional and quantitative definitions

Both functional and quantitative definitions of the transmission grid may be relevant. The functional definitions will provide a common international understanding of what the transmission grid is and the quantitative definition is an individual definition used for practical applications in some control areas.

On basis of the above, a general functional definition of the transmission grid can be made:

“The function of the transmission grid is the transfer of some amount of energy/power over some distance, with some degree of system reliability.”

A quantification of “some amount”, “some distance”, and “some degree” will separate the transmission grid from the distribution grid. The definitions in enclosure 3 indirectly quantify the amount and distance by specifying the connection points in the transmission grid. The transmission grid connects:

- electrical grids.
- different control areas.
- generating units and main point of supply.
- generating units.
- main points of supply.

Furthermore, grids in parallel operation providing support to the higher voltage and grids providing other ancillary services may be considered as transmission.

On this basis, an overall functional definition can be made which covers all of the definitions in enclosure 3:

“The function of the transmission grid is:

- transfer of energy/power provided by the set of elements connecting 1) generating units to main points of supply, 2) generating units, 3) main points of supply, 4) electrical grids in different control areas.
- the provision and transport of ancillary services and support to higher voltage levels”.

No matter whether the power system is functioning as a monopoly or in liberalised surroundings this will always be valid.

In areas with dispersed generation connected to the underlying grids, these grids can, according to the definition, be transmission grids. In cases with local production overflow, energy is transported from the distributed generating units to a main point of supply in the transmission grid.

Although the general definition of transmission grid is *functional*, the practical application is generally carried out in a *nominal* way typically based on the voltage level.

According to the questionnaire, those quantitative definitions of transmission are very different varying between 45 kV and 220 kV. The size and historical evolution of the system play a relevant role in the quantified definition of the transmission grid, and it is obvious that differences exist.

3.3 Update of CIGRÉ definition

An update of the CIGRÉ definition can be considered on the basis of the results from the questionnaire:

"The function of transmission is the transfer of electrical energy/power in bulk from generation or import sources to a main point of supply or export sources, the provision and transport of ancillary services and support to higher voltage levels.

These functions also include transfer of electrical energy/power between electricity grids or control areas, and power support through interconnections and between generating units".

From this definition, each area can specify an appropriate quantitative definition based on the voltage level as an example.

4. Changing conditions for network planning

In order to determine the changing conditions in relation to the transmission network planning it is important to get an overview of the key transport factors which determines the need for transmission grid capacity.

The demand for transport in the transmission grid depends on the production machinery (capacity, placement, production and reserves), the customer power demand, and the exchanges with neighbouring areas. In order to perform network planning a set of fundamentals is required regarding how those factors influence the grid.

The success of planning the future transmission grid depends on the ability to forecast the fundamentals for the network planning. The fundamentals are highly dependent on the socio-development, including the introduction of the open electricity market. The decisions taken in planning generation, supply and transmission will be heavily influenced by the level of liberalisation.

The primary changing condition is the introduction of the electricity market and competition between production companies. Also the increasing international environmental considerations, e.g. RES and visual impact influence the socio-development and by that the fundamentals for transmission network planning. Typically, power systems will not be totally liberalised but re-regulated as system reliability and the environment are considered as well as the electricity market.

In the following, a short description is given of the changing condition. The emphasis is on the introduction of the electricity market for different parts of the world.

4.1 The electricity market

The regulation structure, the market structure and the chosen electricity industry structure determine the function of the market, ref. [2]. These structures vary from one country to another. Hence, it is not possible to make a unified description of a global liberalisation. But independent of the choices, the goal is the same for all countries: to introduce competition in generation and to give each consumer the possibility to freely choose an electricity supplier.

- The *regulation structure* regards the level of liberalisation. The regulator could be a government body or an independent regulator setting up guidelines and rules for the transmission and generation operation and by that the function of the market.

- The *market structure* regards the function of the electricity trade for instance the establishment of an electricity pool or a trade through bilateral contracts. It also regards the type of markets established, for instance the physical spot and the real-time market and financial markets. There will be no emphasis on the market structure in the context.

- The *electricity industry structure* regards how is the generation, the supply and the grid utilities are organised, for instance the 1) establishment of a transmission system operator or an independent system operator, 2) separation of distribution or not, 3) ownership etc.

A general consequence of restructuring the electricity industry structure is the unbundling of grid and generation operations and the establishment of Transmission System Operators (TSOs) or Independent System Operators (ISOs).

The European Union

The European Union (EU) has issued a directive, ref. [3], regarding common and general rules for the electricity single market. This directive formally came into effect on February 19, 1999, signifying that competition would be the norm, not the exception, for electricity trade and electricity production in the EU countries together with Norway and Switzerland.

The EU directive states an overall regulatory structure and allows a high degree of optional choice of how to liberalise. Each member state must fulfil the general rules stated in the EU directive through national legislation, where special national interest can be specified, e.g. considerations for the environment and specific economic frameworks.

In most of the EU member states, new production capacity is established through an authorisation procedure, which means that any company can apply for establishment of new generation provided that it complies with specified planning and energy supply criteria.

The EU directive also specifies the overall electricity industry structure including the unbundling between transmission and production in order to establish competition in the power production industry and a free choice of power supplier for the consumers.

Most of the countries within the EU have a single Transmission System Operator, whose overall task it is to be in charge of the operation, maintenance and if necessary the development of the transmission system and interconnections to guarantee the reliability of the system.

One of the market areas within the frames of the European Union is Nordpool (NordPool, http://www.nordpool.no) covering the Nordic countries Norway, Sweden, Finland and Denmark.

The market structure of Nordpool is an integrated electricity market with one common spot market for physical power trade.

During the last 10 years, the Nordic countries have had new Energy/Electricity Acts, which have started the liberalisation process. Norway started the liberalisation from January 1, 1991, and was followed by Sweden and Finland in 1996-1997, and finally Denmark in 1999. The legislation and regulatory structure varies from country to country, but some topics are common.

The authorities regulate the grid monopolies financial framework to make sure that the monopolies are efficiently operated and that the tariffs are reasonable. The Nordic regulators have chosen different ways to achieve this goal.

Legislation states that in the electricity industry structure the commercial activities such as production, and selling of electricity should be separated from the transmission and distribution grid monopolies.

The ownership and organisation of the main transmission grid is in each country left to one transmission system operator (TSO) in Norway, Sweden, Finland and two in Denmark. There are also a number of regional transmission grid utilities and distribution grid utilities operating under the same legal and financial framework as the TSOs. The TSOs are appointed system responsible by the authorities.

Further information for the European Union and the Nordic countries can be found in **appendix 3**.

United States of America

The Federal Energy Regulatory Commission (FERC) in the USA, ref. [4] is an independent regulatory agency within the Department of Energy that, among other things, regulates the transmission and wholesale sales of electricity in interstate commerce for private utilities, power marketers, power pools, power exchanges and independent system operators. The Commission acts under the legal authority of the Federal Power Act of 1935 the Public Utility Regulatory Policies Act and the Energy Policy Act.

In order to enhance competition in wholesale electric markets and broaden the benefits and cost savings to all wholesale and retail customers, the Commission intends to reform public utilities' open access tariffs to reflect a standardised wholesale market design. Further information on this can be found in ref. [4].

As the liberalisation of the California power system recently has been subject to extensive attention a description of this area is given.

The competitive electricity market of the state of California began operation on March 21, 1998 with the unbundling of transmission and generation and the creation of Californian independent system operator (California ISO) and the now bankrupt power exchange PX (a regional electricity spot market) as the main operationally independent market facilitators. The California ISO and Power exchanges were regulated by FERC and CPUC (California public utility commission) Until May 2000, when the Californian power crises started, the market was functioning smoothly. Additional information can be found in ref. [5] and ref. [6].

Australia and New Zealand

The New Zealand and Australian liberalisation processes have evolved with similar objectives, but in a different manner.

In *New Zealand* the process developed without a regulator, but with guided consultation between the various market participants. This consultative process has now been extended to try to secure individual investments in transmission infrastructure with specific customer contracts.

The main transmission grid in New Zealand is owned by Transpower NZ Ltd, (a government-owned company). Transpower also currently performs the role of System Operator, including dispatch of generation and procurement of ancillary services. At some point in the future, the system operator role could become contestable. There are approximately 30 distribution companies who own and operate the local grids between the Grid Exit Points and the end customers. These companies all operate as private companies, although some are owned by consumer trusts and/or territorial local authorities.

In *Australia*, central regulatory oversight and rules for operation of the transmission systems are provided for all members of the National Electricity Market ("NEM"). However, it is interesting to view the various interpretations by the grid service providers in each state which have certain autonomy within the overall rules. Western Australia is included in this context. While it will never physically be part of the NEM, it has chosen to follow the general rules in the interests of National consistency. Again it has applied some autonomy in interpreting the rules.

In the Australian Electricity Industry, the States of Victoria, New South Wales, Queensland and South Australia are interconnected and operate under the National Electricity Market ("NEM") requirements, which include the National Electricity Code ("NEC") and the Regulatory Test as laid down by the Australian Competition and Consumer Commission ("ACCC"). The ACCC is the National Regulator for the transmission service providers that operate in the NEM.

The NEC is a set of commercial, economic and technical regulations that the participants in the NEM must comply with. The Regulatory Test is the net market economic benefit test for approval of the regulated transmission and interconnection developments. For the inter-regional augmentations, the Test applies the least cost criterion.

4.2 Environmental considerations

Considerations for the environment lead to environmentally friendly technologies often supported by the government. This means that Renewable Energy Sources (RES) and combined heat and power production technologies are on the increase and therefore influence the fundamentals for network planning as well as the introduction of the electricity market.

In November 1997 the EU commission published a whitepaper on Renewable Energy Sources (RES) in which the goal was to increase the RES production to 12 per cent of the energy consumption in year 2010. <u>It is expected that an EU-directive for promoting the RES-production will follow within a year</u>. Different models for a RES market are under consideration with the implementation of RES certificates among the options being considered.

The promotion of RES technologies has in some areas led to large amounts of dispersed generation including wind power. A large proportion of this production is non-dispatchable and dependent on geographical and weather conditions as well as on heat consumption instead of power consumption. The power system is no longer balanced according to the electrical load and the derived need for power production. This creates a dependency on the interconnections and other transport patterns in the grids.

In many areas the public opposition against overhead lines has increased, leading to difficulties when establishing new transmission lines. The opposition is due to the visual impact and the fear of magnetic field exposure and it may lead to delay for new transmission lines for instance with the result of bottlenecks appearing on existing transmission lines.

4.3 Financial considerations

Economic regulation is part of the regulatory structure and includes income regulation for companies with the status of monopoly and regulation of the company economics, e.g. in relation to incentives for establishment of new generation.

Rules for access to the transmission grid and the structure of transmission pricing and the inclusion of constrained costs are elements of importance when considering the changing conditions.

5. Identification of key issues

In order to identify and describe some of the key issues associated with " Network planning in a deregulated environment", the use of case studies, and a questionnaire were considered to be good methods.

A total of nine case studies were received from the system operators in Denmark, Portugal, England & Wales and Ireland, **appendix 2.** Each was aimed at highlighting a particular issue or problem, its consequence and any action taken.

Twenty-one areas, which cover periods of liberalisation between zero and up to fifteen years answered the questionnaire. The questionnaire was aimed at collecting the experience and expectations from areas world wide. Eleven were from the European countries and ten from New Zealand, Australia, USA and the Gulf area. The full questionnaire analysis can be studied in **appendix 1.**

5.1 Case studies

Analyses of case studies flagged up the four main categories of key issues

- environmental issues.
- interconnection issues.
- market issues.
- regulatory issues.

Environmental issues

There is increasing interest in RES providing significant levels of generating capacity. This interest is being promoted by both individual government policies and by European wide targets. The impact of these policies has/will be to connect thousands of MWs of new non-dispatchable generation making up a significant proportion of the overall system capacity. This may result in significant changes to flows on transmission grids.

The special rules that often apply to renewable schemes, such as prioritised production and their technical limitations especially regarding non-dispatchable wind power, ref. [7] may result in problems for the system operator regarding maintaining the balance in the system.

Another impact of environmental considerations is the increasingly difficulty in obtaining public acceptance of new transmission infrastructure. Lead times in excess of five years for new transmission lines are not uncommon because of objections to overhead lines. With new generation schemes typically taking less than two years to construct there is potential for costly system bottlenecks to appear because of the transmission infrastructure developments lack in relation to the generation development.

The location of new renewable energy schemes under Portuguese environmental energy policy has the potential to place additional strains on the transmission grid. Reinforcement of the grid to accommodate the new generation or limiting grid access for the new generation are alternatives that the Portuguese TSO must consider when planning for the future.

Interconnection issues

In the past interconnections were typically seen as having bilateral benefits by providing increased system security, mutual system benefit (such as the need to carry less spinning reserve in the actual area with resulting environmental benefits) and the economic exchange of power.

The development of the electricity market has placed new expectations for the exchange on interconnections. From a market point of view the primary function of interconnection is one of facilitating electricity trading. This can place new stress on interconnections and the transmission system as a whole as the internal transmission grid may not have been planned for the new market conditions. Alternatively, the market may be restricted by limitations on interconnections or the internal transmission grid.

In Denmark, Eltra changed the planning practice by introducing at number of deterministic “pictures” describing different demands for the internal transmission grid, including the new demands from the exchange on the interconnections.

Market issues

The purpose of the market and the function of the transmission system do not always align and this can in some areas lead to high or unstable market prices, large constraint (bottleneck) costs and inefficient use of transmission assets.

The position of the system operator within the electricity industry and its perceived independence often results in the system operator taking on, or being given, new market functions. National Grid in England & Wales has been operating under an incentive scheme to reduce the cost of transmission services (such as reactive power, constraints, reserve) by taking on the responsibility for management of such services. Constraint (bottleneck) costs have been substantially reduced as a result.

Regulatory issues

The phrase ‘Planning in a Deregulated Environment’ is a bit misleading as many system operators now operate under strict guidelines (re-regulated) set down by a Regulator.

The Regulator is often under pressure from many parties who have a wide range of interests and concerns.

Rules set down by a Regulator are generally aimed at encouraging competition but this aim is often in conflict with the management of the transmission system.

In Ireland a change in regulatory direction altered the rules for allowing generators' connections to the transmission system. The new rules placed additional financial and technical complexity on the operation and planning of the transmission system which had to be managed by the system operator.

5.2 Questionnaire analysis

An analysis of the questionnaire, independent of the number of years with experience of liberalisation was performed. The result forms an average picture showing the most predominant facts covered by the analysis.

In addition a detailed analysis of the responses from the areas with the greatest and the least experience were analysed separately with the purpose of identifying potential differences in relation to the average picture. This was also done in relation to whether the company was a TSO, ISO or other. The results can be studied in detail in appendix 1.

Because of the relatively small number of replies and the fact that a large part of the answers come from European countries the results can only be used to indicate a tendency in relation to identification of key issues.

The average picture

The average result from the questionnaires is representative for an area with one to five years of liberalisation and a public, fully independent TSO that owns the entire transmission grid. An independent public authority regulates the TSO, and the transmission business income is regulated. The TSO has to comply with rules governing transmission grid access and offer terms for access to the transmission grid.

The primary activities for the TSO are network planning, system operation, maintenance and construction of transmission grids. A legal definition of the term transmission exists, which is the same as before the liberalisation. There are no exceptions to the definition.

The system operator has access to some generation data and treats it with some kind of confidentiality. The demands for and administration of confidentiality differ widely from area to area. At the same time there is an obligation to publish certain information, including terms of transmission grid access.

In general, load history is based on the system operators' own measurements and the load projection is also performed within the company, typically with load management taken into account. The reliability of the historic data depends solely on the accuracy of the measurements, and it is assumed that this has not changed since liberalisation.

The load projection depends on the development in society. The future electricity price and how it influences the demand for electricity may be an unknown/uncertain factor in the load projection.

The system operator does not handle the openings and closures of generation capacity, but notification rules exist for both opening and closures. These rules state a notification period of a maximum of two years. This means that information on the long-term planning must be based on the TSO's own assessments, and therefore, they are more unreliable than before unbundling of transmission and generation. As regards both dispatchable and non-dispatchable generation, information is achieved both through own assessments and information from the producers.

The transmission system operator is responsible for the development of the planning criteria and performs the transmission grid studies. Since the liberalisation planning criteria did not change and they are still based on technical requirements and economic rationales. In the economic rationales congestion costs are the most significant. Performance indices such as Loss of Load Probability (LOLP) are not used. Single circuit contingency plus planned outages are considered in the planning criteria for national grids. No special criteria for cross-border lines exist. As economic decision criterion the Net Present Value (NPV) is used.

The investment decisions are made on the basis of technical requirements and economic justification. The decisions are approved by the system operator itself, who also finances the investment and who is able to recover the costs automatically. The investment criteria have changed after the liberalisation and fewer investments are made.

The transmission system operator sees the load growth and location as significant uncertainties. Furthermore, both the establishment of new plants and decommissioning of old plants are significant uncertainties. The most important uncertainty from the regulator is that the transmission pricing framework, planning and consent constraint the practical realisation. In relation to network planning the uncertainties are modelled using scenario analyses.

5.3 Key issues

Studying the analysis of the case studies and the questionnaire together with the description of the changing conditions (Chapter 4) it is possible to identify the most important key issues. They can be organised under key issues in relation to the

- changing conditions, including the introduction of the electricity market, new regulation and considerations for the environment.
- planning fundamentals, including the access to the fundamentals (generation, load and exchange).
- planning criteria which have to be applicable together with the fundamentals and the new demands.

Key issues in relation to the analysis methods such as technical and economic methods are not analysed in this report. New methods may be a consequence if a new or updated planning approach is proven necessary.

Changing conditions

The changing conditions influence the planning fundamentals and introduce new demands for the operation and planning of the transmission system.

The introduction of the market means a reorganisation of the electricity industry, including the unbundling between transmission and generation, competition in generation and the consumer's free choice of supplier. This means that both generation and load shall react on the price signals in the electricity market.

The power exchange between different areas are now based on the difference in the electricity prices rather than between countries and based on security. In some cases it is based on bilateral contracts.

The transmission companies have to comply with rules and guidelines from the regulator/government. This may be obligations in relation to the environment, for instance setting special demands for generation technologies and the use of overhead lines. It may also be legal obligations in relation to the market function, transmission pricing and system reliability.

Many areas experience a growing amount of RES, which may have prioritised assets to the transmission grid.

The market function may be regulated by income and transmission prising, while the system reliability may be regulated by penalties for non supplied energy and demand for the system security. Additionally more and more areas experience a growing public opposition against overhead lines.

Planning fundamentals

The liberalisation has led to an electricity system where generation and consumption are controlled by market forces (competition, price signals, electricity price) and regulation. These parameters must be addressed in planning.

Information about the existing and future generating capacity has become more uncertain as a consequence of changing conditions. The unbundling and confidentiality policies have led to some information becoming unavailable for the transmission grid planner. Due to the production companies reactions on price signals this new element, hard to predict, has been introduced. The most important key issues in generation are uncertainties in:

- predicting the establishment of new generating capacity, including when and how much, due to uncertainties in the market price.
- predicting the location of new generating capacity and the dispatch
- predicting the decommissioning of old generation capacity.
- future generation data due to confidentiality policies.

New production capacity and decommissioning of old capacity will depend on the market. It is uncertain whether the market price can lead to a reasonable amount of new capacity and decommissioning old capacity. This concerns the operational security. The important issue for the grid planner is the ability to predict the capacity considering the future market prices.

Also the prediction of power consumption will depend on the consumer's reaction on price signals (elasticity). This uncertainty is considered minimal in relation to other uncertainties.

A consequence of the introduction of the electricity market has been that the bilateral power exchange between countries to some extent has been replaced with spot trade between different areas. The frameworks of the exchange on interconnections have therefore changed, and they are now (or will be) more dependent on the difference in the electricity prices in the interconnected areas. Regulation of access to the interconnections also influences the exchange patterns.

Reinforcement of interconnections between areas will influence the need for reinforcing the wider grid. This means that the co-operation and financing of interconnections are important.

Furthermore, international markets are established leading to the need for closer co-operation in operation and planning of interconnections.

The most important key issues on interconnections are

- changing transport patterns on interconnections and in the internal grid as a consequence due to reactions on price signals.
- the need for international coordinated planning.
- ensuring the financing of new interconnections and the associated internal network.

Regulation may introduce new uncertainties and frames for the transmission network planning, for instance

- environmental regulation leading to increasing amount of RES generation with prioritised grid access. This is limiting the market function and makes generation data even more uncertain.
- income regulation may limit the possibilities of establishing new transmission lines. This results in new demands on the existing ones or limitations on the market function.
- procedures of approval may delay new transmission lines resulting in new demands on the existing grid or limitations on the market function.

Other key issues influencing the planning approach, but not directly a consequence of liberalisation are:

- the increasing amount of non-dispatchable RES generation especially the wind power introduces new demands for ancillary services from dispatchable generation and interconnections.
- the lack of public acceptance for overhead lines may lead to long lead times in establishing new transmission lines. This results in new demands on the existing grids or limitations on the market function.

Planning criteria

It is important that the planning criteria are applicable together with the changing conditions and the long-term fundamentals. As a consequence the most important key issues are whether

- the existing contingency criteria need an update (relaxation or strengthening).
- there is a need for supplemental criteria (economic and performance).

6. Analysis of the planning approach

Transmission network planning must take part in ensuring appropriate system reliability. Adequate transmission grid capacity for the market (adequacy) and the necessary transmission capacity for transport of ancillary services (security) must be ensured. Also the production capacity contributes to the system reliability.

Typically the transmission network planning approach includes an analysis of the reliability based on a set of *fundamentals*, some realistic *events*, under which the system must be able to operate and specified *consequences* that are accepted during operation. These basic elements are still reasonable to consider.

The changing conditions influence the fundamentals for transmission network planning. It is not only the market introduction that is the important change, but also the increasing world wide environmental considerations.

Furthermore, new demands in relation to the operation and planning of the system may arise. This means that the planning criteria have to be re-evaluated in relation to the possible new demands as a consequence of the changing conditions and the changed fundamentals.

Based on the result of the previous chapters four and five, the purpose of this chapter is to:

- analyse the key issues in order to identify the new and changed fundamentals.
- re-evaluate the planning criteria in relation to the new and changed fundamentals.
- evaluate which analysis methods are necessary and sufficient for network planning.

6.1 Changing fundamentals

Independent of the environment in which the electricity system has to function – whether liberalised or not – the basic fundamentals for transmission planning are information of future

- production.
- load.
- exchange with neighbour areas.

External factors controlled by the market and environmental considerations effect the development of these according to chapter 5.

Production capacity

Before liberalisation the transport of electricity for consumption was the most important factor when planning the future transmission network. The transmission and generation functions were typically united in one company meaning that the generation dispatch and production capacity plans would be available for the transmission system planning. Now the market must secure the adequate amount of capacity, and hence the ability to predict of the market price will be crucial.

The system operator's knowledge of the long-term placement, size and the time for establishment of new generation and decommissioning of old capacity is now basically unknown factors just as the production costs and availability.

The development of "national" generation capacity, also depend on the plans in the interconnected areas since the market function across boarders. This can be effected by different regulation, which make the conditions opaque.

The amount of generation from RES was relatively small and caused no specific consideration in the transmission network planning. This is still the case in some areas but in other areas the amount of RES, now effect the need for transmission capacity. A growing amount of RES demands ancillary services and at the same time they may lead to decommissioning generating units that can provide the services.

This needs a rational set of rules to fit into the market in order to be included in the transmission system planning.

In order to ensure the generation fundamentals related to the players in the market the following initiatives may be (more or less) possible

- the system operator develop models for predicting the generation capacity and the production dispatch based on system reliability, the marginal cost for generation, the future electricity price and the future environmental policy. The key problem is the prediction of the electricity price. Scenarios may be needed for this purpose.
- the generation companies can deliver long-term estimates in generation data to the system operator. This may be difficult because of the need for confidentiality in competitive surroundings.
- the system operator uses different scenarios in capacity development and production dispatch for development of a flexible transmission grid structure.

Because of the long lead times for establishing transmission lines in relation to establishment of generation it is considered important that the system operator continues to perform medium- and long-term planning as well as short-term planning.

Regulation may ease access to production data for network planning. When the regulator sets up rules in relation to the exchange of information and for notification of establishing and closing capacity, the producer will be obliged to deliver relevant information to the system operator.

Rules for both establishment and decommissioning of capacity are important. Typically a notification period of maximum two years exists, which means that the short-term fundamentals regarding the installed production capacity may be rather certain, and the long-term assessments rather uncertain. The combination of regulation and the use of scenario analysis will be a solution for the long-term network planning.

Rules for transmission network access and transmission pricing may be fundamental parameters from the regulator used in the assessment/control of establishing new generation.

Publishing confidentiality policies may improve confidence in the system operators and ease the data exchange and co-operation between producers and the system operator in the assessments of the future capacity.

In order to ensure relevant generation fundamentals for network planning regulation is needed. Furthermore, transmission planning must be robust to ensure a long-term network which is flexible to the uncertainties of future generation.

Load

The most significant uncertainties in load projection are growth and location. This uncertainty may have increased due to liberalisation as the consumer reacts on the price signal, but it is assumed to be minimal in relation to other uncertainties.

Exchange of energy (across borders)

Exchange of energy across borders is desirable and in many cases necessary to have a well functioning power market and a safe operation of the interconnected systems. Exchange of energy also contributes to an efficient utilisation of the different production resources in the electricity market.

Interconnections were originally built and operated for security and reserve reasons, but with the international liberalisation they become “ordinary” transmission lines for transfer of energy in the market.

To develop these interconnections further, close co-operation between neighbouring system operators are necessary. This concerns both operation, planning and rules for access to the interconnections. An example of such a co-operation is the development of The Nordic Grid Master Plan, ref. [8].

In principal the planning of interconnections is the same as planning the internal transmission networks. The difference is that the involved system operators have to agree on the planning fundamentals and criteria.

Additional fundamentals for the interconnections may exist. Interconnections are important in the function of the electricity market. It is therefore important how access to the capacity on the interconnections is regulated and the transmission system planning has to reflect this. Different solutions may exist

- prioritised use of the interconnections. This may severely damage the function of the market.
- the principal of “use it or lose it” for a specific capacity.
- full access.

Previously bilateral agreements and the system reliability controlled the flow of energy between countries. In liberalised surroundings marginal costs for generators, price elasticity of consumers and market players’ estimates of future power prices will also be important to be able to estimate flows. Changed flow patterns and, as a consequence, bottlenecks previously not seen could be revealed. The variation in power flows could also be larger and more unpredictable than before.

Hence it becomes important for the system operators to be able to make estimates of the future power prices and in that way be able to predict how the variation in power prices will influence the power flow. In order to predict the future power price scenario analysis may be used.

Financing interconnections has proven difficult, as the profit and the investment cost may be in different countries/system operators. Models on how to share costs have to be worked out and agreed upon among the involved parties. Currently there is an ongoing work on how to finance such “missing links” in Nordel. The report is scheduled in the autumn of 2002.

It is necessary to plan with interconnections, including economic rationales in determination of the exchange and the need of reinforcements. The planning must be done in co-operation with the neighbouring areas both on reliability and financing of reinforcements.

6.2 Planning criteria

Typically the contingency criteria have not changed due to liberalisation. They are based on the n-1 criteria, but vary from area to area dependent of the electricity system.

Yet, more focus on the economy has been a consequence of liberalisation when planning the transmission network. In some areas income/investment regulation has led to lesser investments.

It was found in the questionnaire analysis that two of the most experienced areas (Norway and VenCorp, Australia) consider a modified N-1 rule where actions on the generation or consumption side are authorised to avoid overloads or problems of voltage and stability. The rules are not applied in a strict way. Norway has also reduced the criteria by accepting temporary overloads during N-1 contingencies, i.e. the transmission network is operated closer to the limit in some situations.

This has the practical consequence that implementation of new transmission lines has become difficult as a result of income regulation, which effects the ability to invest. Also difficulties related to planning and consents have been introduced. This is more a consequence of environmental considerations rather than liberalisation.

The possibility and need for reducing criteria depends on the actual system. In a historic conservative planned system the potential of operating the system under harder conditions may be accepted.

No immediate need for changing the contingency criteria seems to be necessary. These criteria are a result of the history of each area, the structure of the transmission network and the production capacity.

There might be a need for supplementing the contingency criteria with rules for the utilisation of interconnections in order to plan the internal networks.

There might be a need for expanding the planning criteria with criteria for system performance (LOLP, technical/economic utilisation of the interconnections).

There might be a need for expanding the planning approach with economic criteria for reinforcement of interconnections. The economic criteria must be in balance socio- and company economic.

The decision includes technical requirements for the operation of the system and socio-economic assessments. This may include a greater emphasis on the economic rationales (the inclusion of cost-benefit) in the decision criteria. The decision between different alternative solutions also includes methods of making the system more effective (non-transmission solutions) rather than reinforcing the network.. Non-transmission solutions may for example be demand side management (DSM), upgrading of existing transmission capacity, improved control of non dispatchable generation or reducing the demand for operating the electricity system.

6.3 Analysis methods

The general picture in appendix 1 does not show a uniform basis of methods used. Transmission network planning is still based on a technical analysis and in few areas supplemented with economic analysis. The traditional technical analysis does not directly address the market aspects.

Few areas plan with probabilistic methods and by absolute measures of the system performance and economy. Many areas foresee an integration of these probabilistic methods.

The expected introduction of the probabilistic methods is in accordance with the results of the re-evaluation of the planning criteria, concluding that the economic rationales have to be considered to a greater extent in a liberalised electricity sector.

Methods for technical analysis

The technical analysis for transmission network planning is a combination of probabilistic and deterministic methods. The methods are used to analyse a need for reinforcement primarily based on reliability. The methods may be different for the internal grid and interconnections. Example of an economic method can be found in ref. [9].

- *Internal grid.* The deterministic methods are the traditional and still the most widespread methods for transmission network planning. The methods consider snapshots of representative operational situations. Through a traditional analysis technical measures (grid capacity, load flow, node voltage, short-circuit power and stability) are calculated. Technical criteria are used to evaluate the result of the analysis.

  The traditional probabilistic methods consider load duration curves and the probabilities of forced outages of generation and transmission equipments. The probabilistic methods calculate the time duration of bottlenecks from grid elements, losses and performance index for instance Loss of Load Probability (LOLP). Performance criteria are used to evaluate the result of the analysis for reinforcements. The methods also calculate the operational cost and also the basis for saved emissions.

  The planning methods are still based on reliability measures for each area as the key point. Reliability criteria for the meshed AC areas also exist, e.g. within the UCTE, Nordel, and others.

For analysis of the need for reinforcements in internal grids the deterministic methods are still necessary and valid. The probabilistic methods are recommended as additional verification together with the deterministic methods, because the measures are more understandable among market players and the public. The performance indices describing loss of load probability or the like and the concept of bottlenecks can be introduced as important market aspects.

- *Interconnections.* Analysing the need for new interconnections or reinforcement of interconnections set focus on the economy as the most important parameter.

  The probabilistic methods used consider load duration curves and the available generation. Some internal grids may be represented, but this may often be a comprehensive task because detailed technical analysis is needed and more areas are involved. The probabilistic methods calculate the time duration of bottlenecks on the interconnections.

Methods for economic analysis

The economic methods are basically probabilistic. The methods are used to calculate economic values of different reinforcements (~ decision on whether to reinforce). Traditionally the economic methods have not been in focus for transmission network planning.

The open electricity market has led to an increased demand for transparency and economically levelled playing fields. Application of economic methods are increasing and developing.

In principle there is no difference in economic analysis on interconnection and on the internal grid. The economic value of reinforcement is typically calculated as the socio-economic benefit based on costs and benefits for the players on the market, i.e. consumers, suppliers and producers in relation to an alternative.

The methods are either based on socio-economics, micro-economics or a combination of the two. This depends on the task and the obligation of the company.

So far it does not seem to be integrated methods available addressing uncertainties in a mathematically correct way.

The economic benefit of a reinforcement or alternative reinforcements are based on reduced costs on the parameters non-supplied energy, environment (emissions), bottleneck fees, transmission losses (in the grid represented) on the one hand; and the investment costs and operation and maintenance costs on the other hand.

Other parameters which are only included briefly in the methods at the moment are the benefits of improving access to ancillary services, the effect of reinforcement on market power/the market function and the improvement of models representing both grid and generation satisfactorily.

To decide whether to reinforce or not economic methods are necessary both on internal grids and interconnections. Economic methods which calculate the socio economics based on costs and benefits in market surroundings are central. They could be supplemented by investment calculations.

The pure technical probabilistic methods for detection of the need for reinforcements of the interconnections are not considered necessary, as it will be covered by the economic analysis.

Methods for addressing uncertainties

The fundamentals in liberalised surroundings are additionally affected by reactions on price signals from consumers and producers. This is contributing considerably to the uncertainty in the long term predictions. Furthermore the introduction of economic methods requires a prediction of the market price in order to be able to calculate the bottleneck costs. This kind of prediction is also very uncertain.

Uncertainties have to be addressed in the medium- and long-term planning in order to ensure the long-term system reliability and the economical optimum. This may be done by using scenario techniques setting up different scenarios resulting in different market prices and in different reactions and developments in generation, load and exchange. Using scenarios is considered the most realistic approach of addressing the planning fundamentals and the uncertain prediction of price signals.

Models for investment calculations based on reduction of economic risk exists from other business, ref.[9], and are also valid for transmission network planning.

The modelling of uncertainties in transmission network planning has been briefly addressed by other groups, e.g. WG38-05-08. ref. [10].

7. Conclusion

WG37-30 with the title "Network Planning in a deregulated environment" was started in May 2000 with the aim of presenting a final report at CIGRÉ 2002. This was not possible because the content and effort were more extensive than expected. Instead a draft report for the SC37 meeting in Paris in August 2002 was submitted.

Members of WG37-30 saw a need for an analysis of the most important key issues in relation to network planning, especially planning fundamentals which are rapidly changing as a result of liberalisation. The analysis in the report can be seen as the "first step" in developing a new planning approach for the transmission network by identifying and discussing the most important key issues.

Methods used for identification of the most important key issues were a questionnaire study, descriptions of case studies and existing planning approaches made by members of the working group.

The number of answers to the questionnaire was twenty-one of which a large part was from European areas. Together with the fact that most working group members were European has had the consequence that the content of the work may be influenced by European experiences and concerns.

Changing conditions

Changing conditions due to liberalisation and environmental considerations have introduced additional uncertainties in predicting the planning fundamentals. The long-term network planning has therefore turned out to be *planning involving large uncertainties*, and it will be an important part of the planning to reduce and address these uncertainties. The main uncertainties are market prices, regulation, transmission pricing, financing reinforcements and the development of the market in general.

The degree of liberalisation and the experiences are different from area to area. Some of the most experienced areas have been liberalised for a period of ten to fifteen years. The questionnaire resulted in an the average picture showing a TSO with an experience of one to five years and with some regulation of the electricity sector. This confirms that it is more common to re-regulate than to de-regulate.

One of the "dark horses" in liberalisation comes from special rules of grid access given to environmentally friendly generation. Seen from a medium- and long-term perspective this generation needs to be included in the market function e.g. using RES certificates.

Key issues

The most important *key issues* detected are uncertainties in the fundamentals regarding *generation*. The time for new capacity and decommissioning of old capacity are important uncertainties like location and size of new capacity. Unavailable generation costs and availability factors will lead to uncertainty in the prediction of the generation dispatch. These fundamentals are highly determined by the market price which needs new methods of prediction. Since they are not available for transmission network planning for at present scenarios may be set up.

A real problem in this area is that generation companies are likely to do very short-term planning so that long-term data for generating capacity may not be available. This problem as an uncertainty can only be addressed through scenarios with the aim to understand the underlying mechanisms.

Markets develop across borders so an important key issue is the *use of interconnections* and exchange of power both within the same market area and with other markets. The focus is changes on exchange patterns and stresses on internal grids.

The changes in exchanges with other areas need to be handled by introducing an international perspective in the planning approach. There might be a need for supplementing the planning criteria with rules for the utilisation of the interconnections due to security and in order to plan the internal transmission grid.

Reinforcements of the interconnections must be evaluated from both an economic perspective and a reliability perspective. A major international problem is to have sufficient financing of reinforcement of cross border interconnections.

It was found that some kind of regulation would be a contributory factor to ensure relevant information.

Re-regulation of the electricity sector is expected to continue, and developing the regulation will be one of the tools to minimise uncertainties in the generation fundamentals, etc. Regulation of the system operator must be transparent and sufficient to cover the obligations of the system operator with regard to system reliability, environment and market function.

Planning approach and analysis methods

The function of the transmission network effects the planning approach and a common understanding has been proved necessary. Consequently the working group recommends considering an update of the CIGRÉ functional definition of the term *transmission* to:

"The function of transmission is the transfer of electrical energy/power in bulk from generation or import sources to a main point of supply or export sources, the provision and transport of ancillary services and support to higher voltage levels.

These functions include transfer of electrical energy/power between electricity grids or control areas, and power support through interconnections and between generating units".

The focus has been on the *medium- and long-term planning* of the transmission grid. A trend has been inclined towards making short-term planning only, because of the long - term uncertainties on the fundamentals.

One conclusion is that long- and medium-term planning is still important as a lead time for new transmission lines in excess of five years is not uncommon. There is a need to develop the medium- and long-term planning methods. The medium-and long-term perspectives also represent some degree of "liberty" to focus on the future regulations and future system in stead of focusing on the past and present problems.

The result of the analysis of the key issues showed that the traditional basic planning on *reliability* (covering the adequacy and security) is still valid. This procedure considers

- fundamentals, i.e. a description of the surroundings in which the electricity system has to function.
- events, i.e. a description of the probable situations under which the system has to function.
- consequences, i.e. a description of the accepted function under the given fundamentals and under the given events.

The analysis also shows that the *fundamentals* are the central key issues changing during the process of liberalisation. The fundamentals have to be revaluated to make it possible to create a long-term transmission grid that is flexible towards alternative developments in the generation capacity, the load and exchange with the neighbouring areas.

In liberalised surroundings the fundamentals are affected by market prices and price signals which contribute considerably to the uncertainty in the long-term predictions. The uncertainties have to be addressed in order to ensure the long-term system reliability. Using scenarios is considered the most realistic method for the time being of handling the uncertainties in the fundamentals for transmission network planning.

No immediate need for changing the *contingency criteria* seems to be necessary. The technical analysis, e.g. load flow is still necessary and the traditional methods are still valid.

The contingency criteria are a result of the history of each area, the structure of the transmission grid and the generation capacity. The possibility and need for weakening of the criteria, depends on the actual system. In a conservatively planned system the potential for operating the system under harder conditions may be accepted. The contingency criteria have to be harmonised on interconnections. This sets focus on international co-ordination.

Network planning covers adequacy and security. Since the security matter has become more important especially for areas with large amounts of non-dispatchable generation, the task of transporting and getting access to ancillary services has to be included in the planning approach. This issue has not been particularly addressed.

Economic frames become more obvious in the market concept and this puts focus on transparency of investments and income. Investments and solutions must be seen in a light with regard to socio-economy and company economy. This means greater emphasis on the economic rationales (the inclusion of cost benefit) in the decision criteria may be necessary.

There is a need to integrate economical parameters in the network planning. This is an optimisation problem which for the moment must be solved manually by using scenarios. The inclusion of economic analysis involves the use of probabilistic methods which recognises the uncertainties and includes the economic risks.

The conclusion is also that the network planning approach now involves a set of additional parameters such as market prices, performance index, socio-economic optimum, price signals, transmission pricing and investment policies.

Future work

The working group has identified a lot of issues that need to be addressed, but does not recommend the establishment of a new working group. Instead, the group recommend that relevant issues are treated in C1 at future CIGRÉ sessions through preferential subjects. If the need for establishing of new working groups should arise, it would, of cause, be possible.

The future work includes a concretisation of how to address the uncertainties by using scenarios. An important task in that connection is to describe the procedure of performing scenario analysis. For this task international considerations are crucial.

As transmission network planning still are based on reliability issues it is an important future task to identify the relevant measures and levels of reliability in liberalised surroundings.

Furthermore, analysis methods for transmission network planning including considerations for transport and access to ancillary services will be necessary to develop (especially for areas with a large amount of non-dispatchable generation). Also finding/developing economic methods, including the market aspects are future tasks.

Methods for analysing transmission grids must include the economical perspective in a transparent way. This task has been started for instance the discussion of transmission prising during Cigré session 2000, ref. [11].

Work regarding coordinated criteria for building and financing of interconnections and the belonging internal transmission capacity would be an advantage for interconnected areas.

Glossary (draft)

Independent System Operator, ISO
The ISO is responsible for provision of a reliable transmission service and day-to-day operation of the total integrated power system. The ISO does not own facilities with responsibility for the reliable and economic operation of a system, ref. [1].

Ancillary services
Voltage and frequency control, short circuit power, protection functions and emergency start equipments.

LOLP
Loss of load probability

NPV
Net present value

RES
Renewable energy source

Transmission System Operator, TSO
The TSO is responsible for provision of a reliable transmission service and day-to-day operation of the total integrated power system as the ISO. The TSO may own the transmission facilities and may not be responsible for economic operation. (Someone else may set the rules for dispatch, which may not necessarily be economic), ref. [1].

Regulator
Has the responsibility to implement laws established by legislative bodies. They have the legal authority to regulate companies within the electricity sector, usually covering the terms or prices which they charge for their various services, ref. [1].

Transmission
The function of transmission is the transfer of electrical energy in bulk from generation or import sources to the distribution level. This function also includes transfer of electrical energy between electricity grids or control areas.

Unbundling
Separation of generation, transmission and distribution operations. This may be done by establishing separate management, accounting and cost responsibility procedures or by establishing separate companies.

Re-regulation
To amend legislation

Deregulation
To reduce regulation

Liberalisation
To introduce competition in the electricity sector through re-regulation or de-regulation

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Enclosure 1, Terms of reference

CIGRÉ Study Committee n°37

Draft proposal for creation of a new working group 26/06/2000

WG n°37-30	Name of convenor: Mrs Jytte Kaad Jensen
Title of the group:	Network planning in a deregulated environment

Scope, deliverables and proposed time schedule of the Group:

Background:
Coming from a bundled electricity system with a controllable and well-defined production capacity and moving towards a deregulated environment, the framework for the network planning has changed. The network must now meet market requirements.
Developing the network as the infrastructure of the market is crucial. An important factor in network planning is that the fundamentals become more unpredictable; especially those regarding dispatchable and non-dispatchable production provide uncertainty.

Scope:
The overall objective of the study is to analyse the need for development of medium- and long-term transmission planning methods in a deregulated environment. This includes the following work:

1. To identify and analyse the changing conditions (legal, economic and environmental) influencing the development of national networks and cross-border interconnections.
2. To describe and analyse the key factors determining the need for transmission capacity and reliability. This includes transport and access to ancillary services. (Reactive power and frequency control).
3. To examine the planning approach and planning criteria, including a re-evaluation of the fundamentals and the methods used.
4. To examine the planner's possibilities of gathering the relevant data, of managing confidential information belonging to the market players, and of managing the demand for publicity.

Deliverables and time schedule:

Installation of the WG:	April 2000
Beginning of the work:	June 2000
Intermediate report:	SC 37 meeting 2001
Final report:	CIGRÉ session 2002

Comments from chairman of SC concerned:

Approval by TC Chairman: Date

List of participants and corresponding members of WG37-30

Australia/New Zealand	Dr. Chandra Kumble	Transpower
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Croatia	Mr Davor Bajs	Energy Institute “Hrvoje Pozar”
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Denmark	Ms Rikke Bille Jørgensen	Eltra (secretary)
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Enclosure 2, Case studies

1. Denmark

Problem – Power unbalances

In Denmark a large extension of dispersed wind power and combined heat and power units have been installed. This type of power production is bound to other things than the power consumption and is therefore non-dispatchable. As the power production and the consumption are not necessarily coinciding, unbalances may occur due either to lack of power or to power overflow and therefore, demands are made of the system and the market possibilities of controlling these unbalances. Unbalances of up to 800-1,000 MW are seen in both directions. This is approx. 25 per cent of maximum consumption and approx. 55 per cent of the total capacity on the interconnections to Norway and Sweden.

Consequences

The large amount of dispersed non-dispatchable generation in relation to dispatchable generation has led to changed transports in the networks. Furthermore, local power overflow can be seen. This has led to transport out of the area via the distribution up to the transmission level. As the system has not been designed for this, too high voltages are seen in the network. The non-dispatchable generation also gives national unbalances, which lead to transports out of the country into the neighbouring areas. This may constraint the market function.

Action

Due to the system reliability the network is in some local areas operated at a lower voltage than the original operating voltage. On grounds of long-term reliability the planning preconditions have been re-estimated and changed in such a way that in the planning process, dimensioning is not carried out based on a single representative situation, but based on various models, for instance on an environment model or on a market model.

Key issues

Integration of RES production, planning with interconnections, new planning scenarios, planning across the national borders.

Problem – National equalisation of prioritised RES production

With regard to power Denmark is separated into two areas: Eastern Denmark which is synchronous with the Nordic countries, and Western Denmark which is synchronous with the European continent. Each of the two parts has its own transmission system operator, Eltra in west and Elkraft System in east.

The Danish environment and energy policy has furthered and prioritised production technologies based on renewable energy and Combined Heat and Power production (CHP). The total installed wind power and CHP in Denmark is at present 4,067 MW of which 3,335 MW is available in Western Denmark. This matches approx. 90 per cent of the maximum consumption in this area.

In Western Denmark a substantially larger part of expensive renewable energy is in fact available as a result of the Danish environment policy.

Consequence

The unequal distribution of non-dispatchable and prioritised production inflicts extra costs on the consumers of electricity in Western Denmark compared to those in Eastern Denmark. In addition the opportunities to trade on the Nordic Power Exchange are limited, as large parts of the consumption in Western Denmark (approx. 45 per cent) are covered by prioritised energy.

Action

This distortion triggered renewed research and discussions about establishing a power connection between the areas in order to balance the difference (physically). But an attempt has instead been made to reach a financial solution through a political accord from 1999, according to which the part of the distortion caused by wind power should be balanced between the western and the eastern part of the country in 2002.

Key issues

Considerations for the environment, planning with interconnections,

Problem – Obligations to the market function
One of the obligations of the transmission system operators is to make sure that the market functions properly. Shortly after Eltra had become part of the Nordic market at Nord Pool the market appeared very fluctuating due to unstable prices within the Eltra area.

Partly due to the bottlenecks and partly due to periods of power deficit, situations with high prices in Jutland/Funen occurred. In an efficient market high prices should result in import of cheap hydropower from Norway and Sweden, but this did not happen in spite of available capacity on the cross-border connections. This was because the interconnections were reserved for bilateral agreements.

Consequence
The transmission system operators were not issued with legal authority to administer the cross-border connections and to control the production plants in order that the operation of the system and the functioning of the market could be ensured.

Action
The fact that the market did not operate properly resulted in Eltra deciding to impose the concept of "use it or lose it" on the market players. This means that market players who have available capacity at their disposal on the cross-border connections have to make it available to the market. Besides, the problems led to amendments to the Electricity Supply Bill (Act No. 375) in which Eltra's authority in relation to the approval and intervention in the arrangements of the market players is specified.

Key issues
The authority of the system operators in relation to the market players.
Planning with open cross-boarder connections without prioritisation.

Problem – Planning with interconnections

AC and DC cross-border interconnections have been built with the aim of bilateral expectations for economic gains in the exchange of power and less installed reserve capacity. Each individual connection has therefore been operated according to predictable, transparent operating patterns and with the agreed maximum load and security on the interconnection and in the internally adjoining networks.

In this way distinct planning conditions were available. The opening of the interconnections on the market results in demands from the market players about equal access and equal security regarding the capacity of the whole interconnection.

Consequence

The internal transmission system is not necessarily dimensioned with n-1 to the maximum capacity on the interconnections. This leads to some congestion in the internal network with local price areas within the TSO area or in some cases to the practice of moving internal limitations to the borders as a consequence.

It highlights the need for a transparent and fair system for paying congestion costs and for allocating these payments to reducing the limitations.

Actions

Concerns raised by market players have outlined the need for methods to evaluate the need for market transports on specific parts of the network.

It has also led to changes in the planning practise by introducing a number of “pictures” one of which is representing the market situation and thus forming the background for determining the market needs.

2. Portugal

Background

At present, the Portuguese electricity transmission network has a peak demand of 6,500 MW and an energy demand of 38 TWh. The generation system is a mix of hydro (35 per cent of the total production in an average year) and thermal (fuel, coal, NGCC). Hydro is basically located in the northern region and thermal in the South. Thus in wet conditions, there is an important flow from north to south and the opposite in dry conditions.

In some 220 kV lines in the centre of the country, overloads even with an average load close to zero can occur in either north-south or the south-north direction, depending on the hydro conditions.

In the past, the network has nevertheless been planned in a quite well-defined scenario that could lead to a minimum of operational constraints.

The problem

The new Portuguese environmental energy policy for the horizon to year 2010, aims at reaching an amount of about 3,600 MW of new renewable energy from wind, solar and mini hydro-electric power stations. The most important portion will be wind – 2,600 MW. Although, there is some uncertainty about the wind resources and their compatibility with national parks and protected areas, it is certain that the wind farms will be located in the northern and central regions of the interior of the country. Therefore, their production will be added to the hydropower and will cause the increment of the already important flows in the north-south direction for which the network is planned.

Any new network reinforcements have a lead time of about 4-5 years (sometimes even more), and the wind facilities can be erected and connected to the network in a 2-3 year scheme. If the renewable plan is implemented without management concerning network transfer capacity, important and non-controlled network constraints will arise – seriously jeopardising the system security or forcing the disconnection of power from pre-existing hydro facilities.

The alternative actions

- Supplement to a master plan to accommodate all the renewable electrical potential resources. The entrance of new renewable candidates will only be allowed, if network constraints were not expected and in a ranking order previously defined.
- Allow the connection of the new candidates in a moderated order, according to the foreseen evolution of the existing network capacities and allowing for moderated

advancement, if candidates accept interruption features proposed by the system operator.

Key issues

Integration of RES dispersed production, new planning scenarios, lead time for transmission reinforcements, transmission network constraints, interruption management.

3. France

Non-transmission solutions in the Nice area

Background

Historically, the installation of large power plants in the French territory was carried out in order to balance the electricity generation and the electricity demand within each region. The aim was to reduce the need for developing the 400 kV transmission network. as much as possible Owing to its geographical features, it was impossible to locate large power plants such as nuclear units in the Provence Alpes Côte d'Azur (PACA) region.

As a consequence, there is a lack of installed power capacity in this region. Generation only consists of hydro and fossil fuelled power plants. Most of these have a low economic efficiency and hardly meet the latest environmental standards. Therefore, the region has to import a large part of its consumption from the Vallée du Rhône power plants. The situation is most critical in the Eastern part of the PACA, in the Nice area, the supply of which completely depends on the transmission network.

The regional electricity imports rely on two very high voltage (VHV) lines:

- in the south of the PACA, a 400 kV double circuit line from the Vallée du Rhône as far as Nice,
- in the north of the PACA, a double circuit line, one circuit operated at 400 kV the other at 225 kV, and then eastward a single 225 kV line with a low transmission capacity.

The problem

In case of a breakdown of the southern line supplying the Nice area, the power flow on the 225 kV northern line immediately exceeds its thermal ratings. As the overload cannot be mitigated with local generation the circuit trips. It results in a deep power cut in the Nice area (higher than 1,000 MW) and much non supplied energy. Even though the pace is slow, the electricity demand keeps on growing with power imbalance as a result as well as the risk of power cuts is increasing.

In other words to operate the whole PACA network according to the security requirements, RTE has to constrain the regional thermal plants which will result in high congestion costs.

Action

In order to make the regional electricity supply more secure, RTE took the decision to build a new 400 kV double circuit overhead line. In addition to a strong reduction in the risk of load shedding, a reduction in the regional congestion costs was also expected.

The project was faced with a strong opposition because of the environmental sensitivity of the area in which it would be implemented (regional park).

The project was discussed in the frame of a regional public debate. Further to this debate, the Prime Minister's staff has decided to re-specify the project in order to meet the environmental requirements as well as the security standards of the power system.

The project henceforth consists of two main actions:

- a network reinforcement: a new 400 kV single circuit overhead line will be implemented where the former 225 kV line was using its towers as much as possible. The aim is to mitigate the environmental impacts. This action is managed by RTE.

- a Demand Side Management (DSM) project: The transmission capacity of the new reinforcement is far less than that resulting from the first decision. As mentioned before, the regional demand keeps on growing. As a consequence it was decided to complete the network reinforcement by a DSM programme. It aims at controlling the growth of the regional peak demand so as to postpone the need for further network reinforcement as far as possible and even to do without. This action is managed by the French Agency for Energy savings.

Issues

- The Transmission System Operator will have to consider the influence of possible actions on the demand side (or development of dispersed generation) when designing network reinforcement strategies
- Increasing influence on local debates in analysing the problems of the power system and specifying solutions

4. Ireland

Problem – Location of new generation schemes

Background

The Irish electricity network is relatively small with current system peak of approx. 4,000 MW. With the typical "Best New Entrant" for large-scale generation at 400 MW this equates to 10 per cent of the system peak demand. Connection of a new generation scheme to the transmission system is only available on the basis of "firm access"[1]. This means that the generation output should not normally be constrained, but if a constraint does arise then the generator will be financially reimbursed by the TSO. In providing the generation connection, the TSO determines the system problems attributable to the new generation when compared to a base case network. Connection of the generation is made contingent on these problems being alleviated, typically by the implementation of transmission reinforcements.

Problem

In simplistic terms the transmission system can be divided into two zones – an export zone with a large amount of high merit generation and an import zone with relatively lower merit generation that is required to run for thermal and voltage support. Because of the availability of gas within the export zone, new generation schemes of the order of 400 MW tend to locate within this zone. The TSO must consider a number of issues, when providing a connection to the new generator:

- Thermal overloads of the circuits in the export zone as more generation is connected within this zone. Thermal and voltage problems in the import zone as less generation may be running there due to the import zone generation being pushed out of merit.
- An increase in constraint costs as a result of constraining off generation in the export zone and constraining on generation in the import zone.
- Transmission reinforcements required to alleviate thermal and voltage problems, thus minimising constraint costs.

The location of new generation in an export zone coupled with the high growth rate over recent years (6 per cent per year) and an environment where it is increasingly difficult to build transmission infrastructure result in planning becoming very complex.

[1] Please note, that rules regarding generator access to the transmission system have subsequently changed since this case study was developed. See case study below.

Alternatives

These problems all interact and a number of options are available to the TSO. At the extreme there are two alternatives:

- Assume unconstrained dispatch of generation. The new 400 MW generation scheme within the export zone would displace a similar amount of low merit generation within the import zone. This would involve removing the import and export constraints by major transmission reinforcement works (construction of new lines, substations and installation of reactive compensation) that will have significant costs and may take many years to complete.

- Respect the constraints imposed by the import and export zones. In this case the new 400 MW generator within the export zone would displace an equivalent amount of generation within this zone as the level of generation within the import zone must be maintained for thermal and voltage support. This option would impose large constraint costs on the TSO as relatively cheap generation within the export zone is constrained off and generation within the import zone is constrained on.

Issues

Balancing the cost of transmission reinforcement against the cost of constraints. Lead times for transmission reinforcements (3-4 years) are typically greater than that of generation schemes (2 years). Lack of control of generation location leading to uncertainties in planning transmission reinforcements.

Problem – Firm and non-firm access for generation

Independent Power Producers (IPPs) seeking connection to the transmission system have been concerned about the lead times associated with the construction of the transmission reinforcements required to accommodate them. Typically, new power stations can be constructed within two years which is often much quicker than the lead times associated with major transmission reinforcement schemes which may take of the order of three to five years. The TSO was required to offer IPPs "firm" access to the transmission system, which meant that the IPP output could not be constrained under normal conditions. IPPs were therefore given connection offers, which did not give them access to the system until all required transmission reinforcements were completed. Historical underdevelopment of the transmission system coupled with the arrival of new IPPs of the order of 300 MW-400 MW on a 4,000 MW system has exacerbated the problem.

Consequence

An IPP expecting to construct a generating station, connect to the transmission system and operate commercially within two years was told that access to the transmission system could not be given for three to five years because of the lead times associated with required system reinforcements.

Action

Concerns raised by IPPs prompted the regulator to issue a direction on "Firm and Non-Firm Access to the Transmission System". This direction meant that the TSO was obliged to offer the IPP firm financial access to the transmission system from a specified date before completion of system reinforcements – i.e. if the transmission system was unable to accept the IPP's output, the IPP would be financially compensated.

Issues

- Constraints may now be inherently built into new generator connections.
- The commercial and technical management of these constraints adds additional complexity to the overall operation and planning of the transmission system.
- The TSO will need to consider methods of reducing constraint costs such as the utilisation of remedial action schemes or the modification of operational/planning standards.
- Influence of regulatory direction on planning the transmission system, the direction is for a limited period only (less than three years) leading to further uncertainty beyond this date.

5. United Kingdom

An Overview of the Electricity Market in England & Wales

Deregulation of the electricity industry in England & Wales began in 1990 with the privatisation of the public owned Central Electricity Generating Board (CEGB) and the Local Area Boards. The CEGB was split into four generation companies: PowerGen, National Power (now further split into Innogy and International Power), Nuclear Electric (which remained in public ownership) and the pumped storage business which was retained within Nation Grid. The transmission system became a regulated monopoly - National Grid. Initially owned by the Regional Electricity Companies (RECs - the privatised Local Area Boards), the National Grid was later privatised in 1995. Around the same time the pumped storage business was sold to Edison Mission. Nuclear Electric was split into Magnox plant which remains under public ownership today as BNFL, and non-Magnox which were privatised in 1996 under the name of British Energy.

This has been a radical transformation. Privatisation was immediately followed by a mass of new entrants in electricity generation. The main focus was on gas fired generation and from virtually zero capacity at privatisation it now accounts for around a third (~23GW) of the generation capacity today. Simultaneously a similar amount of mainly coal and oil fired plant has been withdrawn.

Competition in supply was introduced gradually starting with large users in 1990, leading to full competition in the domestic sector in 1999.

Recently, the electricity market has undergone further reform with the implementation of the New Electricity Trading Arrangements (NETA) in March 2001. Previously the market had operated under the Pool mechanism whereby generators would bid in at the day ahead stage and the most economical bids would be accepted to generate (done for each half-hour period of the day). The most expensive accepted bid would set the system price which was then paid to all generation. Also, availability payments were made to all generators for making capacity available, irrespective of whether they generated or not. On the demand side, suppliers would pay Pool Selling Price for their metered demand in each half-hour period. Under the Pool, generation was despatched centrally by National Grid. In contrast under NETA, generators are able to contract with suppliers directly and self despatch their plant.

The England and Wales electricity market is regulated by Ofgem (previously 'Offer'), who are also responsible for the regulation of the gas market. There are moves to align theses two markets more closely. The national transmission system, owned by National Grid, remains a natural monopoly and as such its income is regulated. Under the current arrangements, a five yearly price control is set whereby operating and capital expenditure, output measures and efficiency targets are agreed. In the latest review, for the first time, there were separate price controls for SO and TO activities.

Managing Transmission Services Costs in England and Wales

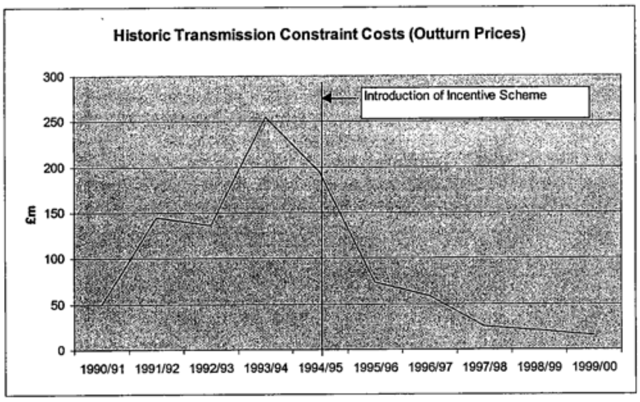
Transmission services (TS) costs represent the cost of running a secure transmission system. It includes the costs of response and reserve services, black start services, transmission constraints, reactive power services, and transmission losses.

When the electricity supply industry in England and Wales was privatised in 1990 National Grid Company was made responsible for operating an efficient and secure transmission system and facilitating competition in the market. TS costs together with Pool uplift costs (i.e energy uplift costs and unscheduled availability payment) were directly passed through to electricity purchaser via the Pool as part of Pool purchase price. There was no single body responsible for managing these costs.

Total pool uplift costs rose exponentially from an initial total of £267m in 1990/91 to £600m in 1993/94. For the same period, transmission constraint costs rose 5 fold from £50m to £255m, which was projected to increase further in the following years.

In 1994, Pool members agreed with NGC a Transmission Services Incentive scheme whereby NGC agreed to bear a share of any increase or decrease in TS costs around an agreed target, reflecting risk and reward profile prevailing at the time. Costs of reactive services and transmission losses were not included until 1996/97. Later on, NGC was also incentivised to manage energy uplift costs. The scheme was negotiated and agreed annually with the target and sharing factors altered according to the prevailing risk and reward profile.

The scheme has proved to be very successful in reducing TS costs. For the period between 1993/94 and 1998/99, NGC consistently reduced TS costs year on year, achieving a 59% reduction over the whole period. Reactive power costs were reduced more slowly but still down by 24%. Energy uplift had been more volatile but with the introduction of incentives in 1997, costs were cut by 87%. More remarkably, transmission constraint costs were reduced from a peak of £255m in 1993/94 to £15m in 1999/00, a reduction of over 94%. Figure below shows the historic transmission constraint costs.



The introduction of TS incentive scheme acted as a catalyst for a change of culture within NGC both as a system operator and transmission asset owner. Innovation and new ways of working were encouraged. Co-operations between TO and SO were greatly enhanced with a shared goal of reducing constraint costs. Some of innovative practices introduced are highlighted below:

- Increased commercial awareness across the company. People became more commercially orientated, realising the impact of their action on TS costs, in particular constraint costs.
- Enhanced co-operation between System Operation and Engineering driven by the shared goal of reducing TS costs. This led to a more flexible transmission outage plan and innovative

maintenance and construction working methods in shortening, changing, deferring and rescheduling outages.

- Use of new tools. This helped identifying and prioritising most expensive outages, leading to the targeted use of limited resources.
- Cost effective investment strategy. This includes investment in new compensation equipment, such as MSCs, RSVCs, etc, to relieve system voltage constraint area, and increasing thermal ratings of key transmission circuits by hotwiring and re-conductoring the circuit and also installing monitoring equipment to achieve even higher ratings.

Under NETA, NGC is also incentivised to manage balancing mechanism costs. NETA operates totally differently from the Pool. The cost drivers and market behaviours are quite different. The challenge for NGC is to continue to deliver the reduction in Balancing Services costs as it has consistently achieved in the past.

Enclosure 3, Definitions of the term transmission

In this enclosure different formulation of the term transmission is presented. Both the replies from the questionnaire and the official definitions from CIGRÉ, EU and the America and Australia organisations NERC and NECA are presented.

CIGRÉ:
"The function of transmission is the transfer of electrical energy in bulk from generation or import sources to the distribution level (and to reduce the investment in generating capacity). This function also includes transfer of electrical energy between electricity grids or control areas".

European Union:
"Transmission` shall mean the transport of electricity on the high-voltage interconnected system with a view to its delivery to final customers or to distributors"

NERC:
Transmission is *"An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems".*

NECA:
Transmission network is *"A network operating at nominal voltages of 220 kV and above, plus any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to, and provides support to, the higher voltage transmission network".*

From the questionnaire the following definitions appear:

The definition in the **Australian** areas covered by Transend Network Pty Ltd, ElectraNet SA and Victorian Energy Networks Corporation is based on the voltage level. A transmission network is a network "*operating at nominal voltages of 220 kV and above plus:*

- *any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network;*
- *any part of a network operating at nominal voltages between 66kV and 220kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network".*

The definition in the **Australian** areas covered by Power and water Authority and western power operation is based on the voltage level. "*A transmission network is all parts* *of the electricity network a network used for transporting electricity at nominal voltages of 66 kV or higher and a nominal frequency of 50 Hz".*

In **Belgium** the transmission network is defined as "*the national network of electricity transmission that includes overhead lines, underground cables and equipment used for transmission of electricity between countries and to direct clients of producers and to distributors established in Belgium and also used for interconnection between power plants and between electrical networks".*

In Croatia the definition of the transmission network is: *"The transmission network is one of the basic parts of electric power system. The task of the network is to connect power plants or other points of supply with large groups of consumers located on longer or shorter distances. Through the network electrical energy produced in any power plant is transmitted to the consumers through several possible ways. According to that, transmission network allows the most economical combination of power plants production at one moment and consumers supply with acceptable reliability depending on its construction."*

The definition in the **Danish** electricity law (Law 375, § 5) is in conformity with the CIGRÉ definition and says that transmission network is *"a collective electricity supply grid which has as its purpose to transport electricity from production locations to a general centre in the distribution grid or to join it to other coherent electricity supply grids."*

In **England** the transmission system is defined as: "*A system which consists (wholly or mainly) of high voltage lines and electrical plant, and is used for conveying electricity from a generating station to a substation from one generating plant to another or from one substation to another", where "high voltage line" means "an electric line of a nominal voltage exceeding 132 kilovolts*.

The **French** Law brings in the expression of Electricity Transmission Public Network but doesn't specify a clear definition of it. This latter should be stated precisely in the Terms Of Reference of the ETPN that is being drafted by the State Secretary of the Industry. For the moment, the notion of "Réseau d'Alimentation Générale" (General Supply Network) is still valid. Besides the facilities operated above 45 kV, it also includes certain distribution facilities (20 kV and below).

In **Ireland** the transmission network is defined as "*the system consisting (wholly or mainly) of high voltage electric lines operated by the TSO for the purposes of transmission of electricity from one power station to a sub-station or to another power station or between sub-stations or to or from any external interconnection including any plant and* *apparatus and meters owned or operated by the TSO in connection with the transmission of electricity. (taken from the Grid Code definition)".*

In **Jordan** "*Transmission of electric power over the 66 kV high tension lines and above There is a legal definition for 'Transmission Network in 15: The National Transmission Network (RNT) comprises the very high voltage (>110 kV) network, the interconnection network, the national dispatch (D. Law 185/95) and all the related assets and legal rights".*

Transmission is not officially defined in **Norway**. Instead the following concept is used: *"The main grid is the nationwide power lines at the highest voltage levels (132-420 kV) complete with substations, plus regional grids which influence the operation of the grid. An exception is 132 kV cable installations built within the licence area. Exception can be made for installations that are included in the definition of the main grid, when the system operator and the licensee agree on this. Such exception must appear from and be justified in an appendix regulating regional and local conditions".*

In **Romania** *all the high voltage lines (220 kV or more) and substations which are interconnected for the transmission of large amounts of electrical power at long distances*.

The definition in the **Spanish** Law (Law 54/1997, § 35) is based mainly on the voltage level, although with a functional possibility of extension: *"The transmission grid is that constitute by all lines, substations, transformers and other grid elements with rated voltage equal or above 220 kV, as well as those other facilities – independently of the voltage- playing a function of transmission or international interconnection"*

The definition in the **German** DVG-Grid Code says "*The purpose of the transmission system is the transmission of electrical energy to downstream distribution systems and the provision of system services. A characteristic of a transmission system is that the power flow in the network is determined essentially by the generation schedule. German transmission systems are generally limited to the voltage levels 220 and 380 kV; in particular cases, a 110 kV network may also have the function of a transmission system.*

A transmission is the technical and physical process relating to injection of electrical energy at one or more points of supply (injection nodes) by a supplier and its corresponding and simultaneous withdrawal by a receiver at one or more withdrawal nodes of a transmission system.."

In the following table the different definitions are categorised with regard to voltage level and with regard to function. Most areas have both a functional and a quantitative definition.

Country	System operator	Voltage level	Function
Australia	- Transend Network - ElectraNet SA - VenCorp - TransGrid	≥ 220 kV Network parts between 66 kV and 220 kV, defined from function Above 132 kV (some meshed 132 kV 66 kV)	The conveyance of electricity Parallel operation and support provision to the higher voltage Parts deemed by regulator to be included Transmission of electricity between generators, distributers and interconnected states.
	Transend Network, Act	≥ 88 kV	The carrying of electricity between different points
	- Power and water Authority - Western power corporation	≥ 66 kV and 50 Hz	Transportation of electricity
Belgium	ELIA		- Transmission of electricity between countries - Transmission of electricity to direct clients of producers and to distributors in Belgium - Interconnections between power plants - Interconnections between electrical networks
Croatia			- Connection of power plants or other points of supply with large groups of consumers. - T transmission of electrical energy from any power plant to the consumers through several possible ways.
Denmark	Eltra		Transmission from production to a centre in the distribution grid Interconnections between electrical networks
England	National Grid	≥ 132 kV	Conveying electricity from a generating station to a substation

			one generating plant to another one substation to another
France	RTE	≥ 45 kV	
Ireland	National Grid		Electric lines operated by the TSO for the purposes of transmission of electricity from - one power station to a substation - one power station to another - one substation to another - from any external interconnection including any plant and apparatus and meters owned or operated by the *TSO* in connection with the transmission of electricity
	12	≥ 66 kV	Transmission of electric power
Jordan	National Electric Power Company	> 110 kV + interconnections + national dispatch	
New Zealand	Transpower New Zealand Limited	66 kV, 110 kV, 220 kV AC system and 350 kV HVDC link	- System operation - Service Provider for the Electricity Market - Settlement Planning information - Security Forecast information
Romania	Transelectrica	≥ 220 kV	Transmission of large electrical power amounts at long distances
Spain	Red Életrica de España	≥ 220 kV + interconnections + other facilities playing a transmission function	

Germany		≥ 220 kV Some parts of 110 kV	Transmission of electrical energy to downstream distribution systems Provision of system services. A transmission is the technical and physical process relating to injection of electrical energy at one or more points of supply (injection nodes) by a supplier and its corresponding and simultaneous withdrawal by a receiver at one or more withdrawal nodes of a transmission system.

Enclosure 4, Planning horizon

Traditionally, different time frames are used in network planning, with different degrees of detail and with the use of different tools and models. Network planning is a process which typically may be broken down into the following stages:

- Very long-term studies
- Long-term studies
- Medium- and short-term studies

Very long-term studies are characterised by a very high degree of uncertainty as the duration may be up to 20 years. The very long-term planning addresses two different planning purposes:

- System design studies, from which broad guidelines for the transmission system development are given and coherent expansion plans for the transmission network are defined. Thus, the design criteria will consist of technical decisions of a strategic nature which in advance will characterise the main features of the transmission network. This also includes aspects related to standardisation and assessment of new technologies.
- Strategic studies, from which the long-term grid topology is conceived. Because of the very long-term perspective, there are still some uncertainties. Consequently, this requires the consideration of a very simplified grid representation.

Long-term studies are tactical studies with the main objective of detailing the very long-term strategic studies. This includes identification of where and when new basic corridors and transmission substations have to be established. Decisions to build are not made.

Simplified models are used which combine optimisation techniques with a relatively precise representation of the grid. Aspects concerning e.g. transient stability limits, voltage violations, reactive power flows, short-circuit capacity, etc. cannot easily be taken into account in long-term planning models. A very important advantage of the long-term studies is the possibility of initiating complementary, time consuming studies, with moderate associated costs. This could be environmental assessments and preliminary administrative procedures.

In the medium- and short-term studies the uncertainties are reduced and detailed models of the power system can be used, including the static and dynamic aspects of the system. Due to the need to adapt the final reinforcement as much as possible to the continuously changing environment, the definitive decisions are made at the short- and medium-term horizons.

- Medium-term decisions include decisions on network structural development, i.e. new lines or new substations. Furthermore, they include a proposal for non-structural reinforcements – which may be revised in the short-term decisions.
- Short-term decisions include facilities with a dynamic installation process; consequently they represent non-structural reinforcements and may include uprating/upgrading of existing lines, new transformers, new reactive compensation equipment, etc.

The actual planning horizons associated with this procedure are influenced by two basic features which may vary from area to area:

- the life of the transmission facilities
- The construction/installation period of the transmission facilities.

This is made complicated by the fact that the construction/installation period for new transmission lines is increasing at the same time as new generation in many cases is implemented much faster than earlier (combined cycle gas generation, wind power plants or others). These circumstances emphasize the need for flexibility in network planning.

The preceding classification of different planning horizons is very general and may be interpreted differently in different areas, Table 1.

	Short and medium-term		**Long-term**	**Very long-term**
	Non-Structural	**Structural**	**Tactical**	**Strategic**
Australia	1-2	5	10	15-20
Belgium	2	7	>7	>7
Croatia		5-10	10-20	
England	2	7		20
France	5	7		10-15
Hungary	3	5-10	10-15	
Ireland	1-2	2-10	10-15	10-15
New Zealand	1-3	3-5	10	10-20
Norway	1	3-5	10	
Portugal	2	3-6	7-10	10-20
Spain	1-2	4-10	10-20	10-20
West Denmark		5	10	20

Table 1 Planning horizons in different areas

WG37-30

Date: December 3, 2002

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Questionnaire Analysis

Appendix no 1
for
WG37-30: Network planning in a deregulated environment

Table of Content

1. Introduction

The transition to a deregulated environment in the electricity industry inevitably changes the traditional way of network planning, partly because the unbundling of transmission and generation introduces new uncertainties and partly because the market introduces new demands for the transmission system. For instance new economic frames are set.

In order to benefit from the experience from different international areas a questionnaire was developed (**enclosure 1**). The aim of the questionnaire study is to identify the key issues related to network planning in a deregulated environment. This report describes the results.

Twenty-one areas responded. Hereof, two responses were received too late to be a part of the total analysis. One was the only response from the United States and it was therefore analysed separately.

The other nineteen responses form the total analysis. Those areas are: Five from Australia, one from Belgium, Denmark, France, United Kingdom, Ireland, Japan, Jordan, New Zealand, Norway, Portugal, Quatar, Rumania, Michigan in the United States and Spain. The response from Germany covers the German transmission system operators Bewag AG, EnBW, HEW, E.ON Netz, RWE Net, Veag. A complete list of the companies that replied is presented in **enclosure 2**.

2. Method

The questionnaire is analysed by performing a total analysis covering all of the nineteen responses, independent of the number of years with experience of deregulation. From this total analysis a picture can be set up showing the most predominant facts describing the average area covered by the analysis.

In addition, the responses from the areas with widest and least experience are analysed separately with the purpose of identifying potential differences in relation to the average picture. This is also done in relation to the organisation, i.e. whether the company is a transmission system operator, independent system operator or others.

The questionnaire analysis is split up into six subject areas and the responses will be analysed for each of these categories with a view to identifying the most important key issues. The categories are:

1. Rules and organisation
2. Definition of transmission

3. Network planning fundamentals
4. Network planning criteria
5. Decision
6. Uncertainties

Wherever possible, the responses are made up in percentages in relation to the total number of responses (19).

Because of the limited number of answers, the conclusions of the analysis must be looked upon with care. The results are used to indicate a tendency in relation to identification of key issues.

3. The average picture

3.1 Rules and organisation

Different approaches to network planning exist due to the differences in experience of liberalisation and the rules and organisation.

The nineteen companies have different experiences in relation to deregulation. Most of the companies have between 1 and 5 years of experience, 22 per cent have more than five years' experience and 16 per cent less than one year of experience.

Years of deregulation	**<1 year**	**1-5**	**6-10**	**11-15**
Number of replies	16 %	63 %	11 %	11 %

Particularly Transmission System Operators (TSOs) (68 per cent) have responded to the questionnaire. Only one area is organised as an Independent System Operators (ISO). The remaining 26 per cent have other company types such as vertically integrated government utilities and network service providers.

74 per cent of the companies are fully independent; i.e. transmission and generation activities are fully separated. In 21 per cent of the areas transmission and generation activities are managed independently within the same company and only 5 per cent are acting without separation.

In 63 per cent of the areas the companies own all of the transmission network, in 21 per cent they own some of it and in the last 16 per cent the companies do not own any at all.

68 per cent of the companies are public, 21 per cent are private and 11 per cent of the companies have other ownerships or are partly private/public.

In 32 per cent of the cases the regulatory authority is a government body, in 42 per cent it is an independent public authority and in 11 per cent it is a combination of these. In 16 per cent of the cases there are no regulatory authority.

84 per cent of the companies have to comply with rules governing transmission network access. Most of the companies that do not have to comply with rules governing transmission network access have less than one year of deregulation.

89 per cent of the companies have an obligation to offer terms for access to the transmission network and 11 per cent do not have an obligation.

The level of transmission business income is regulated for 89 per cent of the companies and for the rest the electricity prices or the network tariff have to be approved.

The average picture shows an area with 1 to 5 years of deregulation and a public, fully independent TSO that owns the entire transmission network. An independent public authority regulates the TSO and the transmission business income is regulated. The company has to comply with rules governing transmission network access and offer terms for access to the transmission network.

3.2 Definition of transmission

The definition of transmission is a result of the questionnaire that is not related to the identification of key issues in relation to network planning. Yet an understanding of the concept is important in relation to determining the activities in the company and so the obligations in relation to planning. The transmission issue is dealt with in greater detail separately (Eltra Doc. No. 113820).

89 per cent of the companies consider network planning as one of their primary activities. Furthermore, 79 per cent and 84 per cent consider system operation, maintenance and construction as primary activities.

74 per cent have a definition of the term transmission. The definition is based upon consideration of asset ownership/charging arrangements (47 per cent), treatment within the planning process (42 per cent), role of the SO (47 per cent) and organisation of network maintenance (42 per cent). The definition has not changed in 74 per cent of the areas.

Exceptions in relation to the existing definition exist in four areas and are as follows:

- Australia, Elektranet: ETSA Utilities 66 kV by derogation is no longer considered as transmission.

- Australia, Western Power Corporation: Control and communication systems are now considered to be transmission.
- Portugal: Mainly communication assets are now considered to be transmission.
- Spain: 400/110-132 kV transformers are no longer considered as transmission.

The primary activities for the TSO are network planning, system operation, maintenance and construction. A legal definition of the term transmission exists, which is the same as before deregulation. In general, there are no exceptions to the definition.

3.3 Network planning fundamentals

In relation to the network planning approach, the planning fundamentals are vital for the results. The identification of key issues in relation to the fundamentals regards the availability and goodness of data. This is influenced by the ability to estimate future developments, the available measurements and available information from power consumers and power producers, i.e. the users of the transmission system.

Data exchange

The technical data, which are necessary as network planning fundamentals, are exchanged on a contractual basis in 63 per cent of the cases. In 11 per cent the data exchange is voluntary, and in 21 per cent of the cases it is done in other ways, e.g. with demand from the regulatory authority.

The data exchange is done with different regularity for the companies. 21 per cent of the exchange are done annually and when required. 32 per cent are done annually, 21 per cent are done when required and 16 per cent is done on request, i.e., 53 per cent percent of the areas have the ability to exchange data once a year.

Confidentiality

Rules for confidentiality have relevance in the case of the use of consultants and third part involvement in general in the transmission network planning.

Even though two of the nineteen companies do not have a clear specification for data confidentiality they treat received data with respect to confidentiality by limiting diffusion of some data. Fifteen companies have confidentiality policies that treat exchanged data as confidential.

Publishing

Most of the companies have to make one or more plans in relation to the development of the transmission system either annually or every two or four years. The contents of the plans are often specified to be some of the following:

- Load forecasts.
- Generation adequacy.
- Transmission constraints.
- Solution to alleviate constraints.
- Historical demand for transmission capacity.
- Future demand for transmission capacity.
- Grid structure plan.

Access to the transmission system

In relation to transmission system planning the rules and frames regarding transmission network access are related to the establishment of a new generation.

One third of the companies do not have to publish anything in relation to the opportunities for access to the transmission system. For one of the companies the opportunities for access to the transmission system are described in the annual plan mentioned above, the rest of the companies have to publish it separately, i.e., 68 per cent in total.

Access to load data

In 47 per cent of the cases the basis for historical load data is gained by own measurements. In 37 per cent of the cases both own and customers' measurements are used. Only 5 per cent rely solely on customers' measurements and 11 per cent receive the data in other ways.

47 per cent of the companies perform the load projections themselves, 42 per cent perform it in co-operation with the customers or with a consultant and 11 per cent make the projections in other ways.

In 68 per cent of the companies, load management is taken into account and in 32 per cent it is not.

Access to generation data

In 53 per cent of the companies generation market information is achieved from the market participants directly and from markets reporters, in 47 per cent of the companies it is achieved only from the participants.

Only in 11 per cent of the cases the network planner is managing the generation establishment and decommissioning, in the other 89 per cent they do not.

The following information is taken into account in assessing the establishment of potential new generation.

	% of responses
Planning permission and/or statutory permission	68
Project type	63
Location with respect to transmission charges	58
Financial security	47
Access to fuel supply	32
Power purchase agreement	21

The following information is taken into account in assessing the decommissioning of existing generation.

	% of responses
Thermal efficiency	42
Project type	42
Financial assessment	37
Company strategy	37
Age	37
Emissions	37
Location with respect to transmission charges	32
Access to fuel supply	26
Ancillary services income	21

The information on the establishment and decommissioning of dispatchable generation is gained from the producer in 26 per cent of the cases, in 11 per cent of the cases it is found through own assessments, and in 58 per cent it is a combination of the two.

To get information on non-dispatchable, embedded and renewable generation 16 per cent of the companies make their own assessment, 47 per cent do it in co-operation with the producer and 32 per cent receive the information directly from the producer.

In 79 per cent of the responses it is confirmed that there are rules for notification of decommissioning of generation capacity. The decommissioning of generation capacity often has to be notified to the system operator and/or the regulator in advance, in some cases it is the ministry that has to be notified. The notification has to be made between 3 and 24 month ahead of the decommissioning. However, in most of the cases the generator cannot be forced to run even though they have to maintain the generation capacity for that period. The notification of decommissioning of generation capacity can also be agreed in the connection agreement/contract or the day of decommissioning can be agreed in the licence for establishing generation capacity.

The rules of notification state a period of a maximum of two years. This means that information for the long-term planning is unavailable and must be based on own assessments. This is therefore less reliable than before unbundling of transmission and generation.

89 percent of the areas have rules for establishing new generation. Already established generators have continuing access to the transmission system in 42 per cent of the cases and in another 42 per cent they have not.

In the average picture, data are exchanged on a contractual basis and it is possible to exchange data once a year. The system operator treats the received data with some kind of confidentiality. At the same time there is an obligation to publish certain information in relation to the development of the transmission system including terms of transmission network access.

In general, ***load*** *history is based on the system operators' own measurements and the load projection is also performed within the company, typically with load management taken into account.*

The system operator does not handle the establishment and decommissioning of ***generation capacity****, but notification rules exist for both establishment and decommissioning. As regards both dispatchable and non-dispatchable generation, information is achieved both through own assessments and through information from the producers. Generation market information is achieved directly from the participants and from markets reporters.*

3.4 Network planning criteria

The formulation of the network planning criteria is mainly based on the technical and economic operation of the system and the demands made by authorities and customers on system reliability, the environment and economy. How the criteria are formulated and used has an important influence on the need for transmission network reinforcements.

In 63 per cent of the areas the system operator is responsible for the authorisation of the network planning criteria and their mode of application and in 32 per cent of the cases it is the regulator. For the last 5 per cent the responsibility lies both with the system operator and the regulator. 63 per cent perform the network studies themselves and in

27 per cent of the cases consultants are involved either alone or in co-operation with the system operator.

The planning **criteria** have changed in 32 per cent of the areas after liberalisation and in 63 per cent they have not. The changes are very different and they include both more economic rationales in relation to the market and relaxation of criteria.

In all areas that replied to the question (95 per cent) the planning criteria are based on **technical requirements** for transmission capacity, voltage and stability and in most areas also on frequency. Other technical requirements are for instance short circuit levels.

Many different **performance indices** exist and the choice of what to use is very different from area to area. 21 per cent use the index LOLP (Loss Of Load Probability). 58 per cent do not use performance indices at all.

The **economic rationale** for the network planning criteria is determined by 74 per cent of the areas. The most significant rationales are:

	% of responses
Congestion costs	68
Transmission losses	47
Cost of loss of load	42
Environmental costs	21

Other economic rationales are ancillary services costs and costs for safety, operation and maintenance.

The **contingency criteria** vary a lot from area to area. Some include a single circuit only and others include both single and double circuit contingencies and single and double generator contingencies:

Number of areas	**N-1**		**N-2**		
	Single circuit	**Single generator**	**Double circuit**	**Double generator**	**Circuit + generator**
5	x				
1	x	x		x	x
3	x				x
1	x	x	x	x	
3	x		x		
2	x	x	x		
1	x	x			

The three most common contingencies are:

- One single circuit only.
- One single or a double circuit.
- One single circuit and a generating unit.

In the planning criteria 74 per cent consider planned outages through the year and 16 per cent do not. Also loss of any single dispatchable unit is considered by 58 per cent of the areas. 37 per cent have special planning criteria for cross-border lines and 47 per cent have not. Typically, those special criteria cover specific demands to ensure system reliability or extra economic rationales:

- *In Japan, technical data are exchanged with the neighbouring utilities and the total system stability among the 60 Hz system is calculated.*
- *In Norway, busbar faults are taken into account in stations close to the border.*
- *In Spain, no transient overload is allowed in lines.*
- *In Portugal the expected value of reduction of global system operation cost due to the increase in power exchange resulting from the new interconnection is considered to be economically beneficial.*
- *In the Australian area covered by Vencorp short time ratings supported by contract load shedding or modified dispatch are used to obtain maximal transmission capabilities.*

Special requirements regarding the quality of supply are as follows:

Quality measure	% of responses
Harmonics	68
Fault level	53
Imbalance	53
Other	26

The results from the questionnaire show that 68 per cent of the areas plan with a horizon of 10 years. The other areas vary between 1 and 20 years. The planning horizon is treated in detail in a separate document (Doc. No. xxx)

In the average picture, the transmission system operator is responsible for the development of the planning criteria and does the transmission network studies. The planning horizon is 10 years ahead.

Since deregulation the planning criteria did not change and they are still based on technical requirements and economic rationales. In the economic rationales congestion costs are the most significant. Performance indices such as LOLP are not used.

A single circuit contingency plus planned outages are considered in the planning criteria and no special criteria for cross-border lines exist. The loss of any single dispatchable unit is also considered.

3.5 Decision

Whether reinforcement is decided or not depends on several factors. The basis that the final investment decision is made upon is:

	% of responses
Economic justification	84
Technical requirements	74
Environmental demands	37
System performance indices	16
Other	1

In 53 per cent of the cases an investment is approved by the company itself, 32 per cent of the companies approve it together with the regulator and in 11 per cent of the cases the regulator makes the approval.

The Net Present Value (NPV) is used by 86 per cent of the areas as a decision criterion. In 53 per cent of the areas the criteria for investment decisions have changed after deregulation and in 42 per cent of the areas they have not. The changes in the criteria are related to inclusion of cost-benefit analyses.

When the regulator has to approve investments, the approved investments have a guaranteed rate of return. Customers are given a choice on transmission, generation or demand management solutions. In other areas, where no change in decision criteria has been seen, the interpretation of the criteria has developed and future changes are expected.

In 68 per cent of the cases the network investments are financed by own companies, in 16 per cent the companies do it in co-operation with market participants and in 11 per cent of the cases the market participants do it on their own.

In the cases where the investments are fully or partly financed by own companies 75 per cent of the companies are able to recover the costs automatically and 16 per cent cannot recover the cost automatically. One company is not sure because the recovery of the cost has to be approved by the regulator.

The criteria for cross-border investments are different from the national decision criteria for 42 per cent of the companies and another 42 per cent of the companies use the same criteria.

53 per cent of the participating companies have made fewer investments since deregulation, 26 per cent make the same amount of investments as before the deregulation and 11 per cent make more investments.

The investment decisions are made on the basis of technical requirements and economic justification. The decisions are approved by the system operator, who also finances the investment and who is able to recover the costs automatically. The investment criteria have changed after deregulation and fewer investments are made. As economic decision criterion the Net Present Value (NPV) is used.

3.6 Uncertainties

The most significant uncertainties in the development of the transmission system are in relation to load and generation:

Uncertainty on load	**% of responses**
Growth	95
Location	53
Annual variations	11

Uncertainty on generation	**% of responses**
Physical location of new plants	84
Decommissioning of old plants	58
Unpredictable production	32
Costs	26
Availability factors	21

Uncertainties in the load projection (growth, location, annual variations, etc.) have always existed, but in a liberalised environment a new uncertainty factor has been introduced – how do consumers react to the electricity prices and how does this affect the load projection.

As a consequence of the unbundling of transmission and generation, the information about the generation is not available as it used to be. The physical location of new capacity and the lack of knowledge of capacity decommissioning are the most significant uncertainties in a liberalised environment. Furthermore, costs and availability factors are significant uncertainties.

Lots of areas consider the unpredictable production as a significant uncertainty. Unpredictable production is typically coming from RES, for instance wind power, and is a consequence of environmental goals in each area. The unpredictable generation is not a consequence of the liberalisation, but it influences the market function.

The most important uncertainty from the regulator is the transmission pricing framework. This uncertainty is seen by 58 per cent of the areas. Uncertainties in the pool pricing rules are seen in 11 per cent of the areas, and 26 per cent responded other and different regulatory uncertainties.

Planning and consent seem to be a general problem as 89 per cent consider it as a significant uncertainty in the planning process. In 37 per cent of the areas the environmental legislation is a significant uncertainty.

In most areas (58 per cent) the uncertainties are modelled using scenario analysis and 26 per cent use both scenario analysis and probabilistic modelling. The rest (16 per cent) either do not model the uncertainties or did not answer the question.

The transmission system operator considers the load growth and location as significant uncertainties. Furthermore, both the establishment of new plants and decommissioning of old plants are significant uncertainties. The most important uncertainty from the regulator is the transmission-pricing framework and planning and consent constrain *the practical realisation. In relation to network planning the uncertainties are modelled using scenario analysis.*

4. The most experienced areas

The four areas with the widest experience in deregulation are subject to a detailed analysis, in which they are compared to the average picture described in chapter 3.

The four areas in question are:

- Australia, Victorian Energy Networks Corporation (**VENCorp**). Deregulated for 6-10 years and a network service provider. This means that VENCorp does not own or operate assets and has not a system operator role.
- United Kingdom, National Grid Company (**NGrid**). Deregulated for 11-15 years and a TSO.
- New Zealand, **Transpower** Ltd. Deregulated for 6-10 years and a TSO.
- Norway, **Statnett** SF. Deregulated for 11-15 years and a TSO.

The four companies are all fully independent and are publicly owned.

4.1 Network planning fundamentals

This paragraph concerns the access and use of the fundamentals in relation to network planning.

Data exchange

In all areas the technical data are exchanged on a contractual basis. This is also the case in the average picture.

The contractual data exchange is required by a State and National Electricity code for VENCorp. In Norway all companies who need a license from the Regulator are obligated to give Statnett all necessary information to develop and operate the system.

At VENCorp, technical data are exchanged when new or existing data changes or on an annual basis, NGrid exchange data on an annual basis, at Transpower it is whenever there are any changes and at Statnett on request.

In the average picture it is possible to exchange data once a year.

Publishing

VENCorp publishes an annual Planning Review describing past network performance, load forecasts, future network constraints and network solutions to alleviate constraints. Specific consultation processes on options to remove constraints, including other than network solutions, supplement the review.

NGrid has to publish a Seven-Year Statement. This assists existing and prospective customers in assessing the opportunities available to them for making new or additional use of the transmission system. Customers may be both generators and suppliers of electricity. In addition, NGrid has to form the basis with regard to the charges for the use of and the connection to the system.

Transpower does not have to publish anything, as there is no regulator. However, the company voluntarily provides information through an Asset Management Plan (AMP) and a System Security Forecast Report (SSF). The AMP outlines significant security issues and possible options of developments and areas requiring discussion with customers before they are implemented. The SSF provides information on security issues over the next decade considering the load forecast and different generation scenarios. There has not been issued a statement of the opportunities for access to the transmission system but this is in process.

In Norway, a Main Grid Power System Plan is published every fourth year. The opportunities for access to the transmission system are also issued in this plan.

In the average picture plans also have to be published, also specifying the terms of network access.

Confidentiality

At VENCorp network data are stored on a registered database and data are not provided to another party without the approval in writing of the data (asset) owner.

An agreement is formed between NGrid and the customer specifying that data needed for the Seven-Year Statement may be published, and that the remainder only may be supplied to network operators connected to the NGrid system. Data are stored on NGrid's private computer network to which access is protected by passwords. Staff is trained in which of the data may be released.

At Transpower, the data are provided by parties connected to the network for operation of the system and for use in planning studies. Only after written permission from the owner of the equipment and after the third party has signed confidentiality agreement, the data are disclosed to third party. However, the transmission network data (data for all equipment and lines owned by Transpower) are provided to all the utilities connected to Transpower's network.

At Statnett technical information is usually regarded as non-confidential. Information that can have influence on the commercial behaviour of a company's must however be kept confidential. This is included in the "Grid Connection Agreement".

Confidentiality is also taken seriously in the average picture.

Load

Historic load data are based on own measurements at VENCorp and Transpower and on own and customers’ measurements at NGrid and Statnett. VENCorp does not take load management into account, as there still is not enough information available in the market to form a basis. The other areas take load management into account.

VENCorp and their customers perform the load projection. In addition, econometric based system level forecast is obtained from external consultants and the distributors provide a spatial forecast. VENCorp reviews and publishes both forecasts.

Transpower performs the load forecasts itself. Both customers and the TSO’s perform the load projection in United Kingdom and Norway. NGrid prepares the national forecasts using customer forecasts to disintegrate them into nodal and regional forecasts.

There may be a tendency of co-operation between the TSO and the customer to perform the load projection. In the average picture, the load projection is only based on own measurements and assessments.

Generation

None of the four companies are managing the generation establishment and decommissioning, but rules for notification hereof exist in Australia, United Kingdom and Norway. This is also the case in the average result.

In New Zealand there are no rules regarding notification, however generators have to establish a contract for connecting them to the grid.

In Australia, the National Electricity Code requires the generators to notify relevant parties. In order to establish new generation the Australian National Electricity Code defines a connection application process. Connection agreements also have termination arrangements.

In the United Kingdom, generators have to give six months notice in order to formally disconnect their plant. However, they can re-declare their availability at any time within the electricity market. A regulatory pressure exists for companies to consider sale of capacity prior to closure. There have been 18 GW of coal-fired plant sold over the past 5 years. Potential generators have to obtain a generation licence and a connection to the transmission (or distribution) network.

In Norway the legislation requires a formal procedure when applying for a license to build new generation. The process usually takes several years. The regulator has to be notified in the case of decommissioning. The generator is usually given a license for a certain period of time. During this period the generation capacity must be operational, but not necessarily in operation.

At VENCorp the information on the establishment and decommissioning of dispatchable generation is received from the producer and the distribution network owner – if embedded. At NGrid the information on the establishment and decommissioning of dispatchable generation is received from the producer and by using own assessments. At Transpower the information is received from the producer alone.

At VENCorp the information on the establishment and decommissioning of non-dispatchable, embedded and renewable generation is received from the producer and the distribution network owner (as the connection provider) and at NGrid by own assessments. NGrid has some limited ability to acquire information via contractual means through the Grid Code. At Transpower the information is received from the producer, and at Statnett the embedded and renewable generation is received from the producer. Non-dispatchable generation is not relevant in Norway as all generation is dispatchable.

The generation market information is received from participants directly in all areas. At VENCorp, NGrid and Transpower the information is also received from market reporters.

Statnett informs that in order to get a licence to build a new power plant the regulatory authority has to be notified according to formal procedures. The information is then public. NGrid informs that they use information on plant status, bid prices and performance from the electricity pool. Other confidential information is received from participants that can be used for internal planning purposes. Information from utility publications and the press are also used.

When assessing the closure of existing generation VENCorp will only be involved with respect to the financial and technical issues.

NGrid takes financial, company strategy, project type, access to fuel supply, ancillary income, age, thermal efficiency, emissions, locations with respect to transmission charges into account.

When market analyses of the Nordic/European market is carried out by Statnett the focus is on environmental issues and marginal cost.

When assessing the opening of potential new generation VENCorp is involved in assessing the connection applications and providing an offer to connect. The financial security, project type, planning permissions and/or statutory conditions, locations with respect to transmission charges may be considered in a connection agreement.

NGrid takes financial security, project type, planning permissions and/or statutory conditions, access to fuel supply, locations with respect to transmission charges in consideration.

At Statnett they carry out their own market analyses to forecast future power prices and on the basis hereof they make their assessment on opening of new generation.

Only in United Kingdom established generators have continuous access to the transmission system.

Conclusion
A tendency may exist of co-operation between the TSO and the customer to perform load projection.

Regarding the planning fundamentals no other specific differences are detected between the areas with the widest experience and the average picture. This means that despite of the experience the access and use of fundamentals for network planning have not changed.

4.2 Network planning criteria

This paragraph concerns the formulation and use of the network planning criteria.

Responsibilities
None of the companies with the widest experience is dispossessed of the responsibility for authorisation and mode of application of the planning criteria in advantage over the regulator or others.

VENCorp is the only company who needs to ensure a consistency between the criteria and the rules issued by the Australian Competition and Consumer Commission (ACCC). The three other companies do not have similar requirements. In other respects, the companies remain responsible for carrying out the network planning. This is coherent with the average picture.

Planning horizon
The planning horizons used by the companies are up to ten years. The smallest horizon is used by NGrid who are planning seven years ahead. VENCorp states that the ten

years planning horizon is based on scenarios as the generation development is not clear. The 10-year horizon corresponds to the average picture.

Technical requirements

Network planning is based on technical requirements. Each company performs technical analyses to ensure fulfilment of the planning criteria. The common technical requirements regard transmission capacity, voltage profile and frequency. In addition to that, stability is considered in all areas except at Transpower. VENCorp also considers fault levels.

NGrid state that they consider health, safety and environmental requirements outside their transmission planning criteria.

Economic rationales

Transpower does not use any economic criteria. For the three other companies, the network congestion costs are systematically taken into account.

In addition, VENCorp and Statnett consider the cost of the transmission losses and the cost of loss of load. VENCorp also integrates the cost of the ancillary services. NGrid and Statnett indicate considering environmental costs, even though this is not the subject of particular planning criteria.

NGrid explains that the minimum-security criteria may be enhanced through economic justification. Consideration may include constraint costs, number and type of customers affected by an interruption and the economic consequences of interruption and transmission losses.

Performance indices

Performance indices are not typically used. Only VENCorp indicates the use of performance indices, relating to the failure rates for plants and the availability of generation.

The use of technical requirements, economic rationales and performance indices is rather coherent with the average picture.

Economic decision

The use of criteria for the economic decision is similar for Transpower, NGrid and Statnett, using the Net Present Value (NPV) of a cash flow. NGrid calculates over a seven-year period and Statnett rank alternatives according to their socio-economic profitability.

At VENCorp the present value of the benefits of an investment has to be larger than the present value of the various costs relating to this investment. VENCorp explains that the timing is usually determined when the benefit in the first year exceeds the equivalent annual cost of the service. The service cost includes the capital, operation and maintenance and Weighted Average Cost of Capital (WACC) (or finance and rate of return) charges.

In the average picture, the most common economic decision criterion used is the NPV.

Safety criteria

Regarding the safety criteria, the image is very contrasted. The deregulation has not lead to a standardisation of the practices.

NGrid mentions a wide range of significant contingencies, which exceed the simple N-1 rule. The three other companies consider all exclusively N-1.

It should it be emphasised that VENCorp and Statnett consider a modified N-1 rule. This rule is not applied in a strict way, but actions on the generation or consumption side are authorised to avoid overloads or problems of voltage and stability. Statnett accepts even temporary overloads during N-1 contingencies.

NGrid does not consider particular processing for the dispatchable production in the contingency criteria, but only the incidents relating to the lines of connection. Transpower and Statnett consider the loss of a generation facility according to a deterministic approach, whereas VENCorp uses a probabilistic approach of modelling the generation.

New Zealand has an insular character and thus no cross-boarder lines are considered at Transpower. At VENCorp short time ratings supported by contract load shedding or modified dispatch are used to obtain maximal transmission capabilities. At NGrid external interconnections are not specifically covered by the transmission-planning standard. Interconnections are covered by separate agreements that may refer to the standard and therefore apply to that extent. Statnett, tighten the criteria by considering busbar faults in stations close to the boarder

All areas except Transpower considers planned outages in the planning criteria.

Transpower and Statnett consider the loss of a single dispatchable generating unit, while VENCorp assumes a full probabilistic modelling of generation in assessing the network adequacy. In England generating units are no longer centrally despatched. NGrid accept bids/offers in the Balancing Mechanism. The transmission standard does not cover generating units but does cover connections from generating units to the transmission system (generating circuits).

In the average picture, a single circuit contingency plus planned outage are considered and no special criteria exist for cross-border lines.

The quality of supply
Deregulation has not lead to giving the quality of supply a lower priority in the planning approach. Harmonics and imbalances are systematically taken into account.

In addition to that, NGrid, Statnett and VENCorp use the “voltage steps“ and the flicker as quality standards. Transpower takes account for its part of “voltage dips during switching”.

Transpower, VENCorp and NGrid take into account fault levels.

Planning criteria revision
The deregulation has not lead to a systematically revision of the planning criteria. VENCorp however has just initiated a public consultation to re-examine the criteria in the market environment. This process is still in progress.

For NGrid and Statnett, the deregulation was followed by a revision of the criteria. For NGrid, the customer choice in connection design was introduced, as there is a wider use of favourable weather relaxation of operational criteria and the criteria were updated to reflect present industry structure. For Statnett, the understanding of the existing criteria has developed. The focus on socio-economical profitability has become stronger. N-1 has developed to socio-economic profitability.

In the average picture, planning criteria has not changed since deregulation.

Conclusion
It appears that the implementation of the deregulation over a long period does not lead to a single scheme.

The companies do not lose their responsibilities with regard to determination of the planning criteria and the analysis, and all the companies share a technical and economic approach of network planning. The choices can be rather different from area to area with regard to the technical, economic and safety criteria, even though certain options are found more frequently than others are.

Most remarkable is to observe that the deregulation process is not systematically accompanied by a revision of the planning criteria. When it occurs, this revision seems to be the result of a progressive process, which can even start several years after the beginning of the deregulation.

4.3 Decision

This paragraph deals with decision making for investments in the transmission system.

Basis for investments

In all areas economic justification is the basis when making the final investment decision. This is also the case in the average picture.

Apart from economic justification, Transpower and NGrid take technical requirements into account for final investment decision making. Furthermore, NGrid also uses environmental demands as a basis for the decisions.

For NGrid the majority of reinforcements are required to meet the security standards. In addition, some schemes are required purely on the basis of a cost-benefit analysis. Some schemes required for security can be enhanced or advanced if there is an economic rationale to do so.

The weighting of the basis for final decision is practically the same for the four most experienced companies as for the average picture.

Approval of investments

The investment decisions are for the four most experienced areas approved by the company itself. However, Transpower approves the decisions together with the market participants.

Statnett in Norway needs a licence from the regulator to build and in Australia the regulator has the right to set allowed revenue for each investment on a periodic basis.

In the average picture investment decisions are approved by the company itself, some do it in co-operation with the regulator.

Changes after deregulation

At Statnett the investment criteria have not changed after deregulation but the understanding of the criteria has developed. The criteria have not changed from those previously used at VENCorp. However, there is now a regulatory requirement to follow a prescribed methodology.

On the other hand, the investment decision criteria have changed after deregulation for NGrid where cost-benefit analysis is now included. At Transpower the customers now have a choice between transmission, generation or demand management solutions.

Investment financing

VENCorp is the only one of the four areas that does not finance network investments. Instead VENCorp procures the network augmentation through a transmission network service provider and pays annual network service charges for this service. VENCorp recovers the cost of the increased service through transmission use of system charges to customers. VENCorp's costs are also recovered in this way.

The other three do finance network investments on their own. Statnett cannot automatically recover the cost, but the legislation grants them a "reasonable" profit over time. Over time users therefore will pay for reinforcements through the tariffs.

Transpower can automatically recover the costs for network investments. However, the recovery is subject to certain regulatory requirements. There are a few investments within the regulatory framework.

The costs can automatically be recovered for NGrid up to the level of their regulated income within a price review period. If justified, expenditure is rolled into their asset base at the end of the regulatory review period. In addition, for their next review there will be an adjustment mechanism correcting for the amount of new generation built.

In the average picture the investments are financed by the company itself, which is able to recover the costs automatically.

Cross-border investments

Transpower does not have any cross-border lines and is therefore not able to answer the question whether there are different investment criteria for cross-border investments in relation to the internal transmission grid. The other three areas all have different criteria for cross-border investments.

When Statnett makes cross-border connections within NORDEL, they have to negotiate with neighbouring countries to agree on a cost split. Socio-economic profitability will still be main investment criteria. Other cross-border connections are based on commercial assessment.

For NGrid the different criteria are purely commercial design based upon the likely income to be attracted. The differences in market price and time of the day are important factors in this commercial decision. At VENCorp market participants are able to invest directly in the transmission network and recover costs through market mechanisms.

It is fifty-fifty whether the cross-border criteria are different in the average picture. Perhaps there is a tendency going towards having different cross-border investment criteria.

Altering of investments

NGrid has made more network investments after deregulation, due to the increase in gas-fired plant displacing traditional coal-fired generation.

In the other areas less investments have been made. This matches very well with the average picture.

Conclusion

Regarding the decision making there is no specific difference between the areas with the most experience and the average picture (1-5 years of deregulation), besides a tendency towards making different investment criteria for cross-border connections in relation to the internal transmission grid.

4.4 Uncertainties

This paragraph concerns the most significant uncertainties in relation to the transmission network planning.

Load uncertainties

In all areas the load growth is a significant uncertainty. This is also the case in the average picture.

For VENCorp it is especially difficult to estimate the load in summer peaking and air conditioning load growth. At NGrid particularly the load with respect to different market segments (commercial, domestic, industrial) give uncertainties, accentuated by loss of disaggregated consumer information.

Besides growth, Statnett also has uncertainties in price sensitivity of load, i.e. uncertainties regarding how the consumers and especially the energy-intensive industries consuming 25 per cent of the electricity consumption in Norway, will react on higher electricity prices. Transpower also has uncertainties in load location and on annual variations.

In the average picture, load location also is a significant uncertainty. Only one of the four most experienced areas has the same uncertainty. This might be a slight tendency of an uncertainty that is no longer considered in a deregulated environment.

Generation uncertainties
Physical location of new plants is a significant uncertainty for all the four areas and NGrid and Transpower also have the closure of old plants as an uncertainty. This matches the average picture where almost all of the areas have physical location of new plants as an uncertainty and half of the areas have closure of old plants as an uncertainty.

Furthermore, Transpower has unpredictable production and availability factor as generation uncertainties. VENCorp also has the availability factor as an uncertainty, but the main issue is when, where and size, as there is no central planning of generation.

Statnett also considers an uncertainty in how future energy/electricity prices will develop in a European competitive market.

Regulatory uncertainties
There is a big dispersion in regulatory uncertainties both for the four most experienced areas and in the average picture.

Transmission pricing framework is considered as a significant uncertainty by Transpower and VENCorp. For VENCorp uncertainties also includes application of the beneficiary testing, price allocation and treatment of generation.

For NGrid and Statnett the most significant regulatory uncertainties is respectively pool pricing rules and income regulation regime.

Planning and environmental uncertainties
In all areas planning and consents regarding construction of new lines are the most significant uncertainties. This is also the case in the average picture.

NGrid is currently constructing two major new routes. It has taken 8 years to secure the necessary planning and consent for a new 70 km overhead line.

Planning process
The four areas with widest experience in deregulation are all using scenario analysis when the uncertainties are modelled in the planning process. This is also the case in the average picture.

NGrid has found it very important to understand the risk of investment – either through its commitment of deferment and are also using probabilistic modelling.

Decision making process

VENCorp incorporates uncertainties into the investment decision making process through full risk and benefit assessment of the project.

NGrid will analyse the main risk to the project and consider their impact in terms of system security and financial assessment, in order to incorporate uncertainties into the investment decision making process.

Statnett uses scenario and sensitivity analyses to consider uncertainties and possible risk in the investment decision making process.

Transpower will identify security issues and try to discover a market solution. If a solution was not agreed to in appropriate time considering lead-time required in getting consents and construction, Transpower would invest in providing a grid solution to maintain service integrity.

Conclusion

Perhaps there is a slight tendency that load location moves from being a significant uncertainty towards not being an uncertainty.

Regarding the uncertainties no other specific difference between the areas with the widest experience and the average picture is detected.

5. Others

5.1 An area of the United States (Michigan)

Apart from the nineteen areas, mentioned in the introduction section, an area in U.S.A. has responded to the questionnaire. In this section, the answers from this area returned by Michigan Electric Transmission Company (METC) are compared with the average picture described in chapter 3.

Rules and organisation

METC is a TSO with between 1 and 5 years of experience in deregulation. The transmission and generation activities in METC are managed independently within the same company. The company is public owned and owns the transmission network.

A regulatory authority exists, which is a government body.

METC has to comply with rules governing transmission network access and offer terms of access to the transmission network, including the fact that the transmission business is income regulated.

Definition of transmission

The primary activities of METC are network planning, system maintenance and construction and system operation.

The term transmission is defined without exceptions and it has not been reviewed since deregulation. The basis for definition is based upon a Federal Electric Regulatory Commission's (FERC) 7 factor test.

Network planning fundamentals
METC exchanges technical data on a contractual basis. The data are exchanged when required. The contract is also containing confidentiality agreements.

The US transmission owners must file a plan in relation to the development of the transmission system and two plans in relation to the opportunities for access to the transmission system.

Historic load data is gained by own measurements, load projections are made by own company and load management is taken into account for METC.

METC does not manage the generation establishment and decommissioning, but it receives generation market information from electricity market reporters and participants directly.

The information taken into account in assessing the opening of potential new generation is Planning permissions and/or statutory conditions, together with Financial security and Power purchase agreements.

METC takes project type, thermal efficiency; financial assessment, age and emissions into account in assessing the closure of existing generation.

METC only gets information on non-dispatchable, embedded, renewable and establishment and decommissioning of dispatchable generation from own assessment.

For METC there is only notification rules when new generation capacity is established, none when capacity is closed.

Network planning criteria
METC performs the network studies and is responsible for authorisation of the network planning criteria and their mode of application. The network planning criteria are based upon technical requirements, economical requirements and the performance index Loss of load probability.

METC uses NPV as a decision criterion. The contingency criteria are the most comprehensive seen in all the questionnaire answers catering for any two circuits and/or generators, double-circuit lines and single-circuit lines. In addition, the ability to consider planned outages through the year is considered.

METC has special requirements regarding the harmonics. The planning criteria have changed after deregulation by mitigation from deterministic to probabilistic criteria.

Decision
The final investment decision is made on the basis of technical requirements and is approved by METC it self. The decision criteria have not changed after deregulation.

METC is financing investments by own company and in co-operation with other.

All though, the investments made by METC cannot automatically be recovered the deregulation has altered the level of network investment to more investments.

Uncertainties
The most significant uncertainties in the development of the transmission system for METC is Load growth, Physical location of new plants, Unpredictable production, Transmission pricing framework and Planning & consents.

The uncertainties are modelled in the planning process with probabilistic modelling.

The major differences between the Michigan Electric Transmission Company and the average picture are:

- *Transmission and generation activities are managed independently within the same company.*
- *The basis for the definition of transmission is different.*
- *Technical data is exchange as required.*
- *Financial security is taken into account in assessing the opening of potential new generation.*
- *The company gets information on non-dispatchable, embedded and renewable generation and on the establishment and decommissioning of dispatchable generation from own assessment.*
- *There are no rules for notification of closure of generation capacity.*
- *Planning criteria has been changed after deregulation.*
- *Network investments cannot be recovered automatically.*
- *More investments are made after deregulation.*
- *Probabilistic modelling is used to modelling uncertainties in the planning process.*

5.2 ISO contra TSO

Among the nineteen areas there is one ISO (ESB National Grid). In this section the questionnaire from the ISO is compared with the average picture derived from the nineteen answers.

Rules and organisation

ESB National Grid (ESB) from Ireland is the only ISO that has answered the questionnaire. The company, which has between 1 and 5 years' experience in relation to deregulation, is a state-owned, fully independent company.

In Ireland the regulatory authority is an independent public authority. ESB has regulated income and has to comply with rules governing transmission network access and has an obligation to offer terms for access to the transmission network.

Definition of transmission

Besides network planning and system operation ESB has settlement system administration, interface with regulator, ancillary services and calculation of transmission charges.

ESB has a legal definition of the term transmission without exceptions. The definition is based upon the role of the SO and has not been reviewed since deregulation.

Network planning fundamentals

ESB is exchanging technical data annually on a contractual basis, and the received data are treated confidentially.

ESB has to make a "Forecast Statement", a "Development plan" and a "Statement of Charges and Payments" annually.

ESB receives historic load data and load projections from own company and customers and takes load management into account.

ESB does not manage the generation establishment and decommissioning. ESB receives generation market information from electricity market reporters and participants directly.

Financial security, project type, planning permission and/or statutory conditions and Location with respect to transmission charges is taken into account by ESB in assessing the opening of potential new generation.

When assessing the closure of existing generation ESB is taken a lot of information into account, the most important factor is age.

ESB receives information on the establishment and decommissioning of dispatchable generation from the producer and own assessment. ESB receives information on non-dispatchable, embedded and renewable generation from the producer.

ESB has rules for notification of closure of generation capacity and for notification of establishing new generation capacity.

Network planning criteria

ESB performs network studies in co-operation with consultants. The regulator is responsible for authorisation of the network planning criteria and their mode of application. The network planning criteria for ESB have technical requirements and use performance indices, but ESB has not selected any economical requirements.

Criteria for economic decision making at ESB are low costs and technically acceptable. The contingency criteria are outage of a single circuit and outage of a generator and a single circuit.

ESB has special requirements regarding the harmonics. The planning criteria for ESB have not changed after deregulation.

Decision

The final investment decision is made on the basis of technical requirements and is approved by ESB and the regulatory. The decision criteria have not changed after deregulation yet.

ESB is financing investments by Own company and in co-operation with market participants. Investments made by ESB cannot automatically be recovered; the regulator has to approve the recovery of costs.

Uncertainties

ESB is of the same opinion as the other companies regarding load, generation, and planning and environmental uncertainties. ESB has its own opinion regarding regulatory uncertainties. This is in relation to the level of the access new generators will have to the system.

The uncertainties are modelled in the planning process with scenario analyses.

The major differences between the ISO and the average picture are:

- *The regulator is responsible for authorisation of the network planning criteria and their mode of application.*
- *Network studies are performed in co-operation with consultants.*

- *NPV are not used as criteria for economic decision making.*
- *Investment decisions are approved by the regulator.*
- *The recovery of network investments has to be approved by the regulator.*
- *The most significant uncertainty regarding regulatory is in relation to the level of access new generators will have to the system.*

5.3 TSO contra other organisations

32 per cent of the responses come from companies that are not organised as transmission system operators. Analysing those separately gives the following major differences in relation to the average picture:

- *If a regulatory authority exists, it is not obvious that it is a government body as in the average picture. In 33 per cent of the cases the regulatory authority is a government body, in 33 per cent it is an independent public authority. In 33 per cent of the cases there is no regulatory authority.*
- *Load management is not taken into account, as is the case in the average picture.*
- *Both dispatchable and non-dispatchable generation information is achieved directly from the producer. In the average picture this is achieved through a combination of own assessments and information from the producers.*
- *The investment criteria have not changed after deregulation and the company and the market participants finance the investments. In the average picture the criteria did change and only the company finances the investments.*

5.4 The least experienced areas

There are three companies that have less than 1 year of experience relating to deregulation. To find out, if the inexperience makes them act differently, the answers are compared to the average picture. The major differences are:

- *Only one of the three companies has to comply with rules governing transmission network access, In the general picture this is 84 per cent.*
- *Two of the companies take access to fuel supply and power purchase agreements into account in accessing the establishment of potential new generation. In the general picture this is only 32 per cent and 21 per cent respectively.*
- *Two of the companies agree that generation costs are significant uncertainties. In the general picture this is only 26 per cent.*

6. Conclusion and identification of key issues

6.1 The average pricure

The average picture shows an area with 1 to 5 years of deregulation and a public, fully independent TSO that owns the entire transmission network. An independent public authority regulates the TSO and the transmission business income is regulated. The company has to comply with rules governing transmission network access and offer terms for access to the transmission network.

The primary activities for the TSO are network planning, system operation, maintenance and construction. A legal definition of the term transmission exists, which is the same as before deregulation. In general, there are no exceptions to the definition.

Data are exchanged on a contractual basis and it is possible to receive data once a year. The transmission system operator treats the received data with some kind of confidentiality. At the same time, there is an obligation to publish certain information in relation to the development of the transmission system including terms of transmission network access.

Load history is based on the transmission system operators' own measurements and the load projection is also performed within the company, typically with load management taken into account.

The reliability of the historical data depends on the goodness of the measurements alone, and it is assumed this has not changed since deregulation. The load projection depends on the development of society. The future market price and how it influences the demand for electricity may be an unknown/uncertain factor in the load projection.

The transmission system operator does not handle the establishment and decommissioning of generation capacity, but notification rules exist for both establishment and decommissioning. As regards both dispatchable and non-dispatchable generation, information is achieved both through own assessments and through information from the producers. Generation market information is achieved from the participants directly and from markets reporters

The transmission system operator is responsible for the development of the planning criteria and does the transmission network studies. The planning horizon is 10 years ahead.

Since deregulation the planning criteria did not change and they are still based on technical requirements and economic rationales. In the economic rationales congestion costs are the most significant. Performance indices such as LOLP are not used.

A single circuit contingency plus planned outages are considered in the planning criteria and no special criteria for cross-border lines exist. Also loss of any single dispatchable unit is considered. The investment decisions are made on the basis of technical requirements and economic justification. The decisions are approved by the system operator itself, who also finances the investment and who is able to recover the costs automatically. The investment criteria have changed after deregulation and fewer investments are made. As economic decision criterion the Net Present Value (NPV) is used.

The transmission system operator considers the load growth and location as significant uncertainties. Furthermore, both the establishment of new plants and decommissioning of old plants are significant uncertainties. The most important uncertainty from the regulator is the transmission-pricing framework and planning and consent constrain the practical realisation. In relation to network planning the uncertainties are modelled using scenario analysis.

6.2 Key issues

Generation fundamentals

One of the key issues in transmission network planning is the uncertainties in the generation capacity planning, i.e. the missing knowledge of the system operator about establishing new capacity and the decommissioning of old capacity. This is a consequence of the unbundling of network and generation.

The most uncertain parameters in relation to generation are:

- Physical location of new plants
- Decommissioning of old plants
- Unpredictable production
- Costs
- Availability factors

In most areas rules for both establishment and decommissioning of capacity exist, with a notification period of maximum 2 years. This means that the short-term fundamentals regarding the installed production capacity may be rather certain, and the long-term assessments uncertain.

Rules for transmission network access may be one parameter used in the assessment/control of establishing new generation.

Confidentiality policies may improve confidence in the system operators and lighten the data exchange and co-operation between producers and the system operator in the assessments of the future capacity.

The use of probabilistic methods and different scenarios in the planning may account for the uncertainties in generation.

Load fundamentals

The most significant uncertainties in the load projection are growth and location. Location might be an uncertainty overshadowed by more important uncertainties discovered due to experience.

The uncertainty in the load may have increased because a new uncertainty factor has been introduced with deregulation. This is how consumers react to the electricity prices and how this affects the load projection.

The uncertainties in load projection due to deregulation are assumed to be minimal in relation to other uncertainties.

The TSO measurements and assessments may be supplemented with customers' measurements and assessments in order to improve the load projection.

The use of different scenarios in the planning may account for the uncertainties in the load.

Planning criteria

A key issue in relation to the planning criteria is the question whether the existing criteria need an update. This may include more economic rationales in relation to the market (congestion costs, ancillary service costs...) and a relaxation or strengthening of the existing contingency criteria.

Other important key issues are the question of the need for new criteria, for instance the inclusion of performance indices such as Loss of Load Probability and special criteria for interconnections.

Decision

When a requirement for reinforcements are detected a decision has to be made. This includes technical requirements for the operation of the system and socio-economic assesments. A key issue in relation to decision is the question whether the existing decision criteria need an update or if new ones are needed. This may include a greater emphasis on the economic rationales (the inclusion of cost-benefit) in the decition criteria.

Other uncertainties

Transmission pricing frameworks are the most important regulatory uncertainty. This is related to the rules for network access for consumption and generation. The frameworks may not be stationary, which results in uncertainties in the assessment of the future generation and the load projection.

Also income regulation is important. This is related to the ability of investments and thereby to the decision and the practical implementation. Another key issue related to the practical implementation is the uncertainties related to planning and consents.

The environmental legislation is not a consequence of the deregulation but it influences the market function. The environmental frames promote the RES for power production, which leads to unknown and prioritised generation. Key issues are unknown generation and prioritised generation.

WG37-30

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Planning Approach

Appendix no 2
for
WG37-30: Network planning in a deregulated environment

Table of Content

1. Introduction

The transition to a deregulated environment in the electricity sector is expected to change the network planning in some ways. In order to detect which changes are directly connected to the deregulation the members of the working group have described the planning approach in their own company. The aim is to detect trends in the changing fundamentals, planning criteria and planning methods.

In order to ensure consistency among the descriptions, guidelines for the organisation were proposed which are based on the main procedure in the network planning approach:

1. Introduction, describing the area concerned and the overall planning approach.
2. Detection of the need for reinforcement, which may depend on technical and/or economic considerations.
3. Detection of possible solutions covering the choice between new transmission lines and improvement of the existing transmission grid, between cabling and overhead lines etc.
4. Final decision, for instance a technical/economic optimisation.

2. Australia

In the Australian electricity industry, the power systems of the States of Victoria, New South Wales, Queensland and South Australia are interconnected and participate in the National Electricity Market ("NEM"). Market and operational and planning requirements, are specified in the National Electricity Code ("NEC"). A Regulatory Test as laid down by the Australian Competition and Consumer Commission ("ACCC") is used to assess the potential benefits to market participants of proposed network augmentations. The ACCC is the National Regulator for the transmission service providers that operate in the NEM.

With respect to the other Australian States:

The island state of Tasmania is set to join the National Electricity Market in the near future when the proposed DC link across Bass Strait ("Bass-Link") is completed.

Due to its geographical isolation from the power systems of other states, Western Australian power systems are not interconnected with the National Electricity Market and are unlikely to ever be.

Given that there are some differences between the different jurisdictions of the Australian Electricity Industry, this review will focus on the NEM.

2.1 Detection of the Need for Reinforcement

The need for network reinforcements may depend on technical and/or economic considerations and are largely determined by criteria related to one or more of the following:

- Maintaining adequate system capacity
- Maintaining adequate system security
- Maintaining adequate system reliability
- Maintaining a satisfactory network quality of supply

The various jurisdictions (states) in Australia's NEM may have their own specific network technical codes that supplement the requirements of the NEC. These place requirements on the Network Service Providers ("NSP") to provide suitable networks in relation to the aspects listed above.

Some states may still employ deterministic criteria such as the N-1. However, it is becoming more common for NSPs to adopt more probabilistic criteria that allow them to defer reinforcements beyond that dictated by the standard N-1 criteria, while at the same time, allowing them to manage the risk to meet the needs to the network users.

Technical Considerations

The NEC is a set of commercial, economic and technical regulations that the participants in the NEM must comply with. It specifies the minimum and general technical requirements in a range of areas associated with system security, reliability and power quality. It also includes a definition of the minimum level of credible contingency events to be considered.

These include the disconnection of any single generating unit or transmission line, with or without the application of a single circuit two-phase-to-ground solid fault on lines operating above 220 kV, and a single circuit three-phase solid fault on lines operating below 220 kV.

The fault is to be assumed to be cleared in primary protection time by the faster of the duplicate protections with installed intertrips available.

Economic Considerations

The ACCC Regulatory Test is applied to proposed system augmentations so that the option that proceeds provides the most economically efficient outcome for the NEM.

The test states:
"An *augmentation* satisfies this test if –

a) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or

b) in all other cases – the augmentation maximises the net present value of the *market benefit*".

The ACCC's Regulatory Test requires Transmission Network Service Providers to consider local generation, DSM and bundled options to be on an equal footing with network options when applying the test.

The advantages that local generation and DSM options may have in relieving transmission constraints are that they may:

- reduce, defer or eliminate the need for new transmission or distribution investment; and/or
- reduce, defer or eliminate the costs and environmental impacts of construction and operation of coal based power stations.

In particular they may reduce emissions of greenhouse gases such as CO_2 and noxious gases such as NO_2 and SO_2.

2.2 Detection of Possible Solutions

When the need to reinforce the network is identified, the solution that best satisfies the technical, economic and regulatory requirements is selected for implementation. Such solutions may include (but are not limited to) the following:

- new transmission lines (within a given jurisdiction as well as interconnecting different jurisdictions)
- uprating of existing line circuits as well as the line itself
- rearrangement of transmission lines and other items of plant as required
- new substations and/or terminal stations
- reconductoring of lines
- use of technological advances where applicable

2.3 Final Decision

The final decision on network reinforcements is ultimately based on the ability of the assets to provide revenue to the NSP while at the same time satisfying the requirements of:

- the NEC in relation to supply quality, security, reliability and
- the Regulatory Test in relation to provide net economic benefits to network users

3. Belgium

The concerned area extends over the territory of Belgium. Ten million of people are living with an annual consumption (2001) of 83 TWh and a peak load of 13.0 GW.

The central position of Belgium in UCTE network has a dominating influence on the flows in the very high voltage network (380 kV). This influence becomes more important with the increasing exchanges due to the new rules in the European electricity market. Belgium is a small country in a large system and has a very limited control on these exchanges and their consequences on the Belgian network. This situation point out the need for a high level of data exchange between countries, as well at operation stage as at planning stage.

At high and medium voltage (220, 150, 70 and 36 kV), the factors having the most influence are mainly the localization of new generation sets and environmental considerations. The localization of new power station and decommissioning of old one, will impact the need of reinforcement of the network. On the other side, the increasing environmental considerations will impact the way the network may be reinforced, which equipments can be taken into account.

Historical methods and criteria were based on reliability standards. This is always taken into account but an evolution is initiated to take more consideration of economical aspect. Modern methods and criteria will have to comply with consequence of deregulation.

3.1 Detection of need for reinforcement

Technical considerations

The analysis of adequacy based on technical criteria is the main aspect for detecting the need for reinforcement.

The method is based on the analysis of some deterministic situations: a peak load situation with all elements available, some standard off peak situations with elements in maintenance. The elements in maintenance are the main power station of each area in Belgium and the lines and transformers in the very high voltage network. These situations assume some basic exchanges between UCTE countries, some variants of exchanges are also analyzed.

For all this situations, load flow and contingencies calculations are made. A first set of contingencies (n-1 contingencies) include all network elements (line, cable, transformer) and all generators. A second set of contingencies (n-2 contingencies) includes all the combination of two elements. The first element must be any generator and the second element may be any network element or generator.

All the states before and after contingencies have to be acceptable. The criteria concern the current intensity in the equipment, the voltage at each node. The current intensities must be lesser than some admissible limit; the voltages must be between to admissible limits (a low and a high). The values for the limits depend of the type of contingencies.

For the states before contingencies and the states after a single contingency, the limits are acceptable limits without duration limitation. For the states after a double contingency, the limits are less strict, an exceed of 10 % is accepted for the current intensities and a decrease of 2.5 % on the lower limit is accepted for the voltage. The limits for current intensities in overhead lines are due to thermal considerations and are therefore depending of the season, during the winter the acceptable limits are 10 % higher than the nominal value and 5 % lesser during the summer.

Another important point deals with short circuit currents that are limited to some acceptable values.

The described analysis is carried out for different scenarios concerning the future. The main assumptions have to define (1) load projections, (2) production capacities development and (3) exchanges with neighbouring countries. The most critical point is the second one that will be responsible for the greatest part of the uncertainties

Economical considerations

Economical considerations are not really taken into account to decide for the need of reinforcement, the actual criteria are still based on technical considerations. But this matter is changing. More and more often, some congestions are encountered during network operation. The associated costs are increasing and a greater attention is given to this. So it can be expected that the economical considerations will have more importance, new methods will be required and new criteria will be defined.

An important effort is made to develop a Power System Modelling. This new tool is foreseen to make economical analyse of the network.

3.2 Detection of possible solutions

The detection of possible solutions is based on the decided policy that deals with network development. Some decisions were taken that bounds the set of possible reinforcements. These are mainly the consequences of environmental considerations. There are some limitations about equipments that may be used (example: cables are preferred to overhead lines).

Some preference will also be given to solutions where the existing equipments will be completed (example: installation of the second circuits on line that where foreseen with multiple circuits).

The possible solutions are compared and the less expensive on the long term are held.

3.3 Final decisions

The TSO will have to publish every two years a development plan of the transmission network. This plan covers a period of seven years. The plan is set up in discussions with the regulation commission (CREG).

The final approbation of the development plan is given by the federal minister who is responsible for Energy.

3.4 Analysis methods

Technical methods

Methods are historically based on reliability standards. The method is based on the analysis of some deterministic situations: a peak load situation with all elements available, some standard off peak situations with elements in maintenance. For all this situations, load flow and contingencies calculations are made. All single and some double contingencies are taken into account. All the states before and after contingencies have to be acceptable. The criteria concern the current intensity in the equipment, the voltage at each node. Another important point deals with short circuit currents that are limited to some acceptable values.

Some effort is made to develop a data mining tools to analyse the load flow and contingencies results of a large amount of situations probabilistically generated.

Economics methods

Economical considerations are not really taken into account to decide for the need of reinforcement, but an important effort is made to develop a Power System Modeling. This new tool is foreseen to make economical analysis of the network.

4. Croatia

The process of Croatian electricity market establishment has started at the beginning of 2002. Till that day all legal aspects were solved (acceptance of the energy law, electricity market law, oil market law, gas market law and energy activities regulation law). Each consumer with an annual consumption greater than 40 GWh is now free to buy electricity on the market.

The only Croatian power supply company (HEP) will be re-organised. New companies will be established namely HEP-Production, HEP-Transmission, HEP-Distribution and HEP-Supply. They will have separate accounts, but will be legally under the company called HEP-Group. The HEP-Group will be partly privatised.

Transmission System Operator and Market Operator will be within the same company - CISMO (Croatian Independent System and Market Operator), independent from HEP-Group legally and financially. Establishment of the ISMO and the HEP-Group is awaited till the end of 2002. Croatian Energy Regulatory Council (CERC) was also formed.

4.1 Detection of need for reinforcement

The HEP-Transmission is the owner of transmission assets, while the ISMO uses these assets in order to allow transactions and to make balancing between production and consumption. Transmission network planning is an obligation for both of them, but final approval has to be given by the CERC.

Technical considerations

Guidelines for the transmission network planning are given in the Grid Code. Transmission network should be constructed according to the (n-1) criteria. In the case of unavailability of a single transmission network branch (overhead line, cable, transformer, interconnection line) following events should not happen:

- Permanent disturbance of operational variable limits (voltage, frequency) and equipment loading (maximum permitted current), which could be dangerous for safe operation of power system, or which could cause equipment damages and expected life time reducing.
- Loss of stability of some power plants or electrical power system in general.
- Necessary change or interruption of long term contracted electrical energy transmission (import, export, transit).
- Electrical energy supply interruption despite usage of the reserve capacities in the network.
- Disarrangement distension in the electric power system as a consequence of the protection activity.

Busbar faults and a loss of double system circuits are permitted conditioned that the electric power system is expected to withstand consequences with a help provided from neighbouring countries or control zones.

The (n-1) criteria must be satisfied for the worst expected operational state (winter peak, maximum production, different power plants dispatching).

Besides that, some special requirements about stability (steady state, dynamic, transient) are given in the Grid Code.

Economic considerations
The ISMO and the HEP-Transmission have to make transmission network development plans taking into account economic considerations. Economic criteria have not been clearly defined yet.

4.2 Detection of possible solutions

Possible solutions for transmission network development are:

- Construction of new transmission lines (new route or already used route – lower voltage level)
- Up rating of existing branches
- Usage of the special devices (phase shifters, FACTS)

Some basic principles for transmission network planning have been defined in the vertically organised system and not been changed yet by the regulator (CERC):

- Croatian transmission network should be constructed as independent and self-sufficient network according to the (n-1) criteria.
- Transmission network should be connected to neighbouring power systems (Serbia, B&H, Hungary, Slovenia, Italy) if these connections are of common interests. Electrical energy transits for third parties are permitted if safely operation of Croatian power system is not imperilled with such transits.
- More intensive development of 400 kV network and less intensive development of 220 kV network is expected. Temporary usage of 400 kV lines under 220 kV operational voltage is permitted.
- Concerning problems with transmission network corridors, routes and environmental protection, in general new lines should be constructed as double system circuits (equipped with one circuit if necessary).

4.3 Final decision

Final decision is based on the economical estimations, in general on the ability to recover the revenue for the investments. This ability is estimated according to the expected costs of electrical energy not supplied, loss decreasing, and profit from the expected exchanges through the network (third parties).

5. Denmark West

Eltra is the transmission system operator for the West-Danish power system and owner of the 400 kV grid and interconnections. Eltra is by law responsible for the long-term planning of the transmission system which covers the 150 kV and 400 kV grid. Furthermore, Eltra is also responsible for the planning of interconnections to the neighbouring areas.

The liberalisation in Denmark started in 1999 and all customers will be free to choose electricity supplier from 1. January 2003. The West Danish power system is characterised by a large amount of nondispatchable locally placed RES generation.

The planning approach has to ensure that the transmission system can fulfil the overall function, considering certain reliability. This concern the:

- adequacy, i.e. adequate generation and grid capacity in relation to the customers demands.
- security, i.e. necessary ancillary services and grid capacity in relation to the system demand.

The actual transmission network planning covers the adequacy, but considerations for ensuring sufficient grid capacity for transportation of ancillary services is also becoming an important part of the network planning.

The overall strategy for transmission network planning is based on a long-term grid structure and a set of design criteria based on n-1 contingencies covering lack of a line or a transformer in the transmission grid. When a need for reinforcement is detected, the solution is often included in elements of the long-term grid structure to ensure a minimum amount of overhead lines in the landscape. Together with the establishment of new overhead lines reconstructions are made.

5.1 Detection of need for reinforcement

Technical considerations

The method used for detection of the technical need for reinforcement is deterministic and is based on a three stage rocket:

- Fundamentals in consumption, generation and exchanges with neighbouring areas. The fundamentals describe the electricity system in a deterministic base situation.
- Events to be handled during the base situation.
- Acceptable consequences on an event.

Representative base situations ("images") are described through the fundamentals and they are worst case situations in relation to the internal consumption ("security of supply image"), market function/demand ("market image") and for utilisation of the RES generation ("environment image"). Load flow analysis is performed on the base situations.

The events are based on the n-1 contingencies covering lack of a transmission line or a transformer. They also cover planned outages in the grid and the production capacity. This is described in tree different planning criteria, A, C and D, which cover the adequacy and determine the need for new transmission lines:

- Criterion A must ensure the utilisation of the production plants and the interconnections in N-1 situations.
- Criterion C must ensure security of supply in the lower voltage grids in N-1-G[1] situations in the winter period, where no revisions are considered and in N-1-2G or N-2[2]-G situations in the summer period, where revisions are considered.
- Criterion D evaluates the conditions in seldom occurring operation situations for instance loss of an extra transmission line.

The transmission line outages are based on statistical analysis of the availability and the production capacity outages on experience.

The criteria are tested on the worst case situations and the consequences are for instance thermal overload and excess of voltage limits. If the criteria A, C and D are fulfilled, the adequacy is satisfactory and sufficient transmission capacity in Eltra's area is present for the utilisation of production, interconnections and for fulfilling the power demand. If the criteria are not fulfilled, there may be a need for transmission line reinforcement.

Criterion B covers and the system dynamic stability and the need for ancillary services i.e. the security.

No technical criteria exist at the moment for detecting the need for reinforcement of the interconnections. This is related to the market demands for the exchange. Criterion A is used for detecting needs for reinforcement of the internal grid as a consequence of the market utilisation of the existing or decided interconnections.

Economic considerations
Probabilistic methods are applied in a certain extent to examine the operating costs if the grid is not expanded but no specific economic criteria exist for the purpose of detecting a need for reinforcement.

[1] Generating unit
[2] A double circuit line

The need for reinforcement of the interconnections based on demands from the market is a new task in the transmission network planning. No economic criteria exist yet, but they are expected to come and to be based on the socio economics. The need for internal transmission lines as a consequence of interconnection reinforcements is also expected to be detected from new economic criteria supplemented with the technical ones.

5.2 Detection of possible solutions

Solutions for reinforcing the 400 kV grid are based on a long-term transmission grid structure representing the "fully"-developed 400 kV grid. This long term grid structure is looking approx. 20 years ahead. It is based on meshed 400 kV overhead lines. The 150 kV grid is run in parallel with the 400 kV grid. The structure has been developed in consideration of visual environment, economy and system reliability.

Solutions for reinforcements in the 150 kV grid are also based on this long-term structure. Furthermore, the structure is determined by reconstruction of the 150 kV grid, e.g. by using combined 400 kV and 150 kV circuit lines, removed lines or cabled sections. This is the result of the governments' framework for the consideration of the visual environment.

5.3 Final decision

At present, reliability and environment are given a high priority in the final decision. There is a tendency towards performing a technical/economic optimisation more than optimising the security of supply.

With the regulation of the revenue cap of grid owners and transmission companies new requirements and incentives have been introduced to create increased efficiency. This does not advance the incentives for grid investments.

5.4 Analysis methods

Technical methods

The technical methods regarding grid planning are a combination of probabilistic and deterministic models. The methods are used to detect a technical need for reinforcement based on criteria. The methods are different for the internal grid and interconnections.

For analysis of Eltra's internal grid deterministic methods are used, considering snapshots of representative operational situations. The traditional load flow analysis etc. calculates the grid capacity, the load flow, node voltage, short-circuit power and stability. Technical criteria are used to evaluate the capacity and the needs for reinforcements.

Also probabilistic methods are used to analyse the internal grid. The methods consider load duration curves and the probabilities of forced outages of generation and transmission equipment. The probabilistic methods calculate the duration time of bottlenecks in grid elements and the performance index Loss of Load Probability (LOLP). No absolute criteria for performance exist.

To detect the technical need for reinforcements on interconnections to other price or market areas only probabilistic methods are used considering load duration and the available generation. The probabilistic methods calculate the time duration of bottlenecks on the interconnections. No technical criteria exist to evaluate the needs for capacity.

Economic methods

The economic methods in the grid planning are mostly probabilistic. The methods are used to calculate the economic value of different reinforcements (~ decision whether to reinforce). Traditionally the economic methods have only been used a little for transmission grid planning. The open electricity market has lead to an increased application of these methods, and they are still developing.

At present the models are basically used for analysis on interconnections to other price areas. The economic value of a reinforcement is calculated as the socio-economic benefits based on costs and benefits for the players on the market, i.e. consumers and producers.

In particular two different probabilistic models are used at the moment (Eltra doc nr. 96812 "Eltra's Model Tools for System Analyses" [ref x]). The one is a mixed hydro/thermal Nordic model called "Samkøring", describing the interconnected Scandinavian countries, Norway, Denmark, Sweden and Finland and areas in the neighbouring countries. The model includes the interconnections and divides the area into internal market sections within the Nordic areas.

The calculation typically covers load duration, spot prices in separate areas, marginal utility value, bottleneck costs. These calculations form a good basis for the socio-economic cost-benefit analysis.

There is a close cooperation among the Nordic countries on models and data.

The other model is a thermal model "Sivael" which describes Jutland and Funen in detail (e.g. wind power and local CHP) and includes internal sections and all interconnections to other market areas.

Both models calculate the economic benefit of reinforcement or between alternative reinforcements based on reduced costs on non-supplied energy, environment (emissions), bottlenecks, transmission losses (for the grid represented) on the one side and the investment costs and operation and maintenance costs on the other side. The bottleneck costs on the interconnections are the difference in the electricity price in the interconnected areas.

In the Eltra area the benefit of improving access to ancillary services is considered to be a significant factor in the decision. At the moment no systematic methods of pricing this advantage exist.

Methods are developing so that it is possible to study the market forces. Models describing the market function including the producers' possibility of using market power have been developed. This model calculates the producers' benefit in a non-ideal market system, where market power is a natural consequence. The desire/possibility of using market power depends mainly on the market structure, but also on the bottlenecks in the transmission system. This means that reinforcement might be a measure to reduce the possibility of using market power.

The described methods for economic analysis are also developed to a version that includes a description of the internal grid ("Sivael-net" and "Samlast"). This means that it will become possible to perform the economic analysis on the internal grid.

No specific method for optimising transmission investments is used.

6. France

This chapter provides a brief review of the planning methods implemented by RTE that operates and maintains the French Transmission System. These methods are applied to the French transmission networks that include the whole facilities operated at 400, 225, 90 and 63 kV. By other respects RTE is responsible for the development of these networks.

Broadly speaking, the planning of the French Transmission Networks proceeds of a technical/economic approach. The investments carried out for developing the networks must provide a solution at the least cost to a technical problem duly identified. These investments should be profitable i.e. expenses they induced must be balanced by the profits they generate. Only some investments may be decided according to a pure technical criterion. For instance, the electric supply security of the large cities is planned according to a technical criterion (level of back-up).

6.1 Detection of need for reinforcement

As far as the issues of the transmission networks are concerned, the detection of a need for reinforcing the network is achieved by combining a technical and an economic approach. RTE seeks to associate the related costs to any technical constraints, mainly the overloading of a line, a cable or a transformer. These costs can be either the:

- expenses directly incurred by RTE i.e. the congestion costs
- expenses related to the damages undergone by the Community as a consequence of the failure induced by the constraint.

More precisely, RTE is used to evaluating the expected value of these costs by taking account of the probability of occurrence of the constraint.

Technical consideration

With regard to the development of network, the criterion that triggers constraint analysis is the overloading of one, even several transmission facilities. This analysis can be carried out according to the two following approaches:

- The deterministic approach, which postulates that the network must be able to incur incidents such as a line tripping for normative conditions without any trouble. These normative conditions are generally critical situations like the peak hours for various periods in the year, winter, inter season and summer in order to take account of the seasonal variations of the demand and of the transmission capacity of the lines. Various normative assumptions concerning the hydro generation can also be studied. The studied incidents are generally N-1 single circuit, cable or transformer (possibly combined with the loss of a generator). However, nothing excludes the study of N-k situations more rare but likely to generate very significant costs, owing to the expected amplitudes of the consequences.

- The probabilistic approach where the detection of a constraint is achieved on a sample of situations of unavailability of the production units generated according to a Monte Carlo method. A N-1 analysis is applied successively to all the dipoles, for each of these situations. The results obtained are then of a statistical nature (frequency of constraints, for instance) This method is rather applied to the analysis of the 400 kV interconnection network.

Economic consideration
The main feature of the RTE's approach in term of decision making is that it does not rest on the strict technical application of the N-1 rule that would lead, in the event of a dipole overloading, to immediately justify a need for a network reinforcement. Operating actions making it possible to solve the constraint resulting from the incident are simulated and the expenses induced by these actions are calculated. These are mainly

- load-shedding i.e. the demand on some adequate buses is reduced until eliminating the constraint. The yearly non supplied energy is generally estimated through computations using load duration curve. The expected value is assessed according to the probability of the incident. The Non supplied Energy is valued using normative costs differentiated according to the importance of the failure (MWh) during the incident.
- generation re-dispatch i.e. the generation dispatch resulting from the electricity market is modified so as to eliminate the constraint. The drop of generation and the corresponding rises are valued on the basis of costs reflecting the adjustment market. The valuing of the costs of congestion is generally achieved within the frame of a probabilistic approach by implementing an algorithm of optimisation for the generation. The objective of the optimisation is to control the transits in the N situations, and for any N-1 situation, by minimizing the fuel costs.

It should be noted that operating actions at null cost can also be simulated.

6.2 Detection of possible solutions.
Once a constraint has been detected and valued, the network planning lead to answer the two following questions:

- Is a network reinforcement necessary?
- In the affirmative, which is the best strategy from a technical/economic point of view?

A strategy is a set of solutions, possibly staggered in time. All the technically realistic solutions are considered:

- construction of a new OHL, underground cable, …
- insertion of transit regulation devices

The strategy, studied on the long run, must take into account the environmental requirements. The expenses induced by actions required for meeting RTE's commitments relative to environment are included in the global cost of the strategy.

For each of the strategy considered as feasible, a network study is carried out in order to assess its technical and economic efficiency with regard to the constraints detected previously.

6.3 Final decision

The decision to reinforce proceeds of an analysis in two times:

Identification of the optimal strategy.
It is carried out through network structure analysis and the comparison of the various alternatives on the basis of the results of the valuing process carried out previously.

For each strategy, its Net Present Value is calculated as the difference of the discounted costs (costs of the system operation and capital expenses) related to this strategy and the similar costs related to the strategy which consists in making nothing.

The optimal strategy is the one presenting the largest NPV. By other respects, the NPV must be positive so that the strategy is profitable.

Decision of investment
For each investment composing the optimal strategy, the study is carried out:

- over a sufficiently large period of time so that the profitability of each investment is guaranteed
- sufficiently limited so that the confidence in the results is not affected by the uncertainties of the forecasts

In order to make sure that an investment is profitable, its Benefit per Invested Euro (BIE) is calculated. The BIE is the estimate, related to each Euro of the capital investment, of the discounted net benefits (profit minus expenses) of a reinforcement computed over the ten year period following its commissioning. The profits relate to:

- the cost of non supplied energy,
- the costs of congestion and ohmic losses.

An investment is profitable if the BIE value is positive and this criterion must be met so as the decision could be taken.

Once the profitability has been checked, RTE calculates the Ratio Benefit Cost (RBC) as the ratio of the annual benefit to the total capital cost of the investment. It aims at determining the optimal commissioning date for the investment. Without any budgetary constraint, this date is that for which the RBC is higher than the discounting rate used by RTE for the economic calculations.

The computation of the BIE and the RBC is periodically updated as well as each time the cost of the investment has significantly changed. It may result in modifying the previous decision. By other respects, should the project be no longer profitable, the previous decision would be written off.

7. Hungary

In the early 90s there was only one company group (trust) called MVM covering all the fields of electricity supply in Hungary:

- system operation
- generation
- transmission
- distribution
- trade

Then the distribution and most of the generation were privatized, they became separate companies. Also in the early 90s, Hungary announced its intention to join the UCTE. UCTE specified many requirements to be met. One of these was the necessity of (n-1)-criterion for the transmission network.

Because of the strategic aim of the Hungarian power system (i.e. joining the UCTE), (n-1)-criterion for transmission network and strengthening of interconnections to UCTE network became the key elements for network development. (The Hungarian transmission network can still meet the (n-1)-criterion only with the support of the meshed 120 kV distribution network.)

In 2001, the system operation was separated from MVM, and MAVIR Hungarian Power System Operator Company started its operation, based on the activities of the National Control Centre. The ownership of the national grid was kept by MVM, i.e. MAVIR is functioning as an ISO. A new Electricity Act in compliance with the EU legislation was passed in 2001 but most of its chapters are to be in force as of 1 January 2003. The tasks of different organizations of power industry are defined by this new Act. In 2002, there is a transitory period concerning also the network planning approach. The responsibility for network development has been being transferred from the owner of the transmission network (MVM) to the system operator (MAVIR).

7.1 Planning approach

The planning approach based on the new Electricity Act (to be in force as of 1 January 2003) is still under consideration (relying also on the long years' experiences of MVM) but expected to be as follows:

Power system operator co-ordinates and if it is necessary, initiates the network development according to the technical necessity and least cost principle.

Technical and economic considerations

System operator makes "rolling" network development plans in each second year based on the plans (requirements) of transmission and distribution network license holders and additionally taking into consideration of (n-1)-criterion, transmission capacities, long term strategically issues for the whole system and international developments.

Different long term (for about 15 years) deterministic development plan scenarios are made. Short term plans are made and necessary developments to be realized are chosen comparing the different scenarios and their most common parts. The developments are evaluated economically for long term.

7.2 Final decision

System operator submits its proposal for network reinforcements to the regulator. The regulator decides whether reinforcement can really be considered as one for the safe and efficient operation of the electricity system. In case of affirmation the regulator approves the investment cost of the reinforcement to be included into the electricity tariff.

8. Ireland

The Power System Planning function within ESB National Grid (Ireland) is responsible for:

- the long term development of the 400kV, 220kV and 110kV interconnected network
- the provision of access to the transmission network for power producers and demand users
- interconnection planning
- dissemination of public information on the development of the transmission system

The general principle of the ESB National Grid planning approach is to ensure the co-ordinated development of a reliable, efficient and economic system for the transmission of electricity for the long-term benefit of transmission users.

8.1 Detection of need for reinforcement

Technical considerations

Power system analysis tools are used to analyse thermal, voltage, short circuit and dynamic issues using transmission system models to determine network development requirements under a deterministic set of planning criteria.

The planning process starts with a horizon year review (which looks approximately 15 years ahead) which feeds into a development plan (for the next 7-10 years) out of which projects are implemented as required. The planning process must also consider issues of operation, maintenance and protection of the transmission system as well as interaction with other system users.

The primary aim of transmission planning is to ensure the integrity of the bulk transmission system. The transmission system is designed to operate within normal thermal and voltage ranges for credible demand and generation patterns under intact network conditions.

Under maintenance and contingency conditions (single contingency (N-1), overlapping single contingency and generator outage (N-G-1), and maintenance – contingency (N-1-1)) the system is designed to operate without widespread system failure and instability, maintaining voltage and thermal loadings within defined limits.

Additional criteria are also applied to security of supply issues, limits are placed on the level of demand that can be fed by a particular number of circuits and the generation capacity connected to the system at a particular point.

Economic considerations
Using power system analysis and production costing tools the operating costs of the transmission network are forecast. Generator constraints and network losses are the main transmission costs considered within the planning process.

While these cost are considered when comparing the overall economic and technical justification of alternative reinforcement options, they do not currently drive the requirement for network reinforcement as cost optimisation incentives for constraints and losses are not yet in place.

Other wider economic factors that influence planning of the transmission system are facilitating access for independent power producers and developing interconnection capacity thus encouraging increased competition in the electricity market.

8.2 Detection of possible solutions

Following identification of a potential violation of the technical criteria or of an economic justification, a number of alternative solutions are compared from a technical and financial point of view. With overhead lines becoming increasingly difficult to build alternatives such as upgrading the existing network, changing network running arrangements, automatic control schemes or generation constraints must also be considered. With these alternatives additional consideration must be given to system complexity and reliability issues. Solutions should be consistent with the longer-term strategic development of the network.

8.3 Final decision

The selected plan is generally the most economic, technically acceptable solution taking into account the long term strategic development of the network, environmental considerations and the overall benefit to transmission system users. One critical factor in the final decision making process is the considered achievability of the required solution in the required time frame.

9. New Zealand

TRANSPOWER NZ LTD, (a government-owned company), owns the main transmission grid in New Zealand. Transpower also currently performs the role of System Operator, including dispatch of generation and procurement of ancillary services. At some point in the future, the System Operator role could become contestable. There are approximately 30 distribution companies who own and operate the local networks between the Grid Exit Points and the end customers. These companies all operate as private companies, although consumer trusts and/or territorial local authorities own some.
The network companies in New Zealand operate under a light-handed regulatory framework. Their network assets are valued using the Optimal Deprival Value (ODV) methodology to value sunk investment.

It was originally envisaged that any additional investment in the main grid (either for capacity or growth) would be protected by a new investment contract, to prevent asset stranding and subsequent write off through the ODV process. However, to date Transpower has only managed to negotiate a few signed transmission contracts for new investment, and none for core grid investment as customers have been unwilling to agree to pay for new investments.

Transpower has therefore become a reluctant investor, and in order to maintain security for parts of the grid, it is forced to invest as a “last resort”. This, coupled with customer resistance to its pricing allocation methodology, has resulted in many investments based on posted terms and conditions. There is, however, only limited and temporary legislated support for its posted contractual terms and conditions.

As part of the latest round of government reform of the electricity industry, a working group called the Transport Working Group was set up to review the new investment process and recommend a way forward. New investment rules are under development. These will require Commerce Commission authorisation (regulatory authority) of potential price fixing and anti-competitive aspects, and may change before coming into effect in their final form.

At the time of writing, new investment processes for the grid and distributed networks are being carried out independently by the owners of the various networks and the grid. However, under a proposed new industry governance structure, new processes are being developed for suppliers and customers to agree the description and level of the service component of transmission contracts. They also need to agree on transmission replacement and expansion options, and mechanisms for pricing these services.

There are two parts to the overall process. The **first part** sets out:

- A process for Transpower and its customers to agree the description and current level of the service component of transmission contracts (where contracts exist) for existing services.
- A structured annual cycle in which Transpower engages with its customers in relation to its planning assumptions and expected future investments required to maintain described service levels. This cycle culminates in Transpower issuing a statement of investment opportunities and a service delivery plan.
- A process to cover situations where transmission providers and transmission customers have not been able to agree, that facilitates transmission customers collectively agreeing changes to transmission service levels, or the introduction of new services, that affect more than one customer. This process also allows for the Electricity Governance Board to test and potentially reverse these decisions if they are found to be inconsistent with the interests of the end-consumers they affect.

The **second part** sets out a decision process for pricing transmission services in a manner consistent with specific pricing principles prescribed in the Government Policy Statement (GPS). This process applies to the pricing of Transpower’s existing services, and to all transmission services that are supplied pursuant to an agreement reached with customers by way of the collective decision-making process.

Under this process the transmission provider is required to satisfy the Electricity Governance Board **(yet to be established**) that it has used robust design processes and principles to develop its pricing methodology, and that the methodology conforms with the GPS principles and objectives.

The process also provides for checks and balances to ensure the methodology is applied correctly. Transmission purchasers would agree to be bound by the correct application of a pricing methodology that has been confirmed by the Electricity Governance Board as complying with the GPS principles and objectives.

In developing the approach set out in the draft rules, solutions were sought that:

- Identify service definitions and service measures meaningful to both customers and the transmission service provider, and to use these measures to define the current level of service provision and as a base for future transmission replacement and expansion decision-making.
- Open up the market to non-transmission solutions and alternative suppliers wherever possible, including the use of demand-side management approaches.
- Ensure clear accountability for the delivery of transmission services on the part of suppliers.

- Ensure services are provided at the standards of quality and security required by transmission customers (or grid users) through a process of agreement with those customers.
- Expose information and foster debate on the lowest cost method of meeting service requirements in situations where Transpower remains the sole supplier.
- Provide for an appeal process to the Electricity Governance Board if a party considers a decision taken by transmission customers is not in the interests of the end-consumers directly affected. The Electricity Governance Board may, under certain circumstances, reverse a decision which is found to be inconsistent with the interests of end-consumers.

9.1 Detection of need for reinforcement

The need for a new investment in the Grid is largely to be determined by one of the following criteria:

- Transpower’s ability to maintain the agreed service levels;
- Customer requirements to either enhance security or capacity;
- Reinforcement needed to maintain the security of supply from the Grid
- Constraints affecting Energy market bilateral contracts between supplier and purchaser.
- Major refurbishment & replacement expenditure due to age.
- New generation or load connections.

The main grid security levels currently under proposal and set out below, have been developed taking into account international practice, the longitudinal nature of the New Zealand system and, in particular the lack of adequate generation in some of the major load centres.

- (N-1) security criterion to meet winter peak demand for the credible worst-case generation dispatch scenarios. It is assumed here that no circuits are taken out for maintenance during winter peak load periods.
- For regions with a net transfer of more than 600 MW[3], (N-2) security criterion is used to meet summer peak demand since circuits are taken out for maintenance during the summer period. This should be based on normal dispatch scenarios, not extreme dispatch scenarios.

Any load that has significant impact on the business should have N-2 security. In particular this applies to Central Business District (CBD) loads for winter and summer

[3] The net transfer is defined as net of region load minus the generation in the region. The transfer level is under review and is not yet final.

peak load conditions. The N-2 security may be with or without break, depending on the situation. The customers are considering this at this stage.

Technical considerations

Technical considerations include the ability of the grid to meet agreed level of security, service levels across a range of dispatch and demand scenarios. In particular Power flows under normal conditions and abnormal conditions need to ensure there are no constraints or cause safety issues to equipment & human.

Load flow, Short circuit analysis and stability analysis (voltage, transient and dynamic oscillations) is normally considered in developing and approving solutions.

A number of engineering, operational factors are considered in narrowing down options to a limited set of technically, operationally, environmentally and economically feasible solution.

Considerations such as balancing local security to through flow security to a region are also one of the major considerations in selecting the type of substation configurations. Often the busbar arrangements are also determined based on the market rules for security i.e. size of generation loss covered by the spinning reserve.

There are other environmental legislation issues also considered in determining the technical option. For example noise level, oil containment, visual impact etc.

Economic considerations

There are a number of economic factors, which are used in determining the most economic solution. They are:

- National Benefit test (Identify solutions with highest national welfare)
- Revenue certainty for the investment;
- Efficiency Gains
- Least cost solutions

In a deregulated environment it is hard to determine the beneficiary. Given this environment economic considerations often boils down to a simple exercise of investing in least cost options that has a revenue certainty. Often economic efficiency factors such as dimensioning conductors to minimise losses are often ignored due to higher initial capital cost associated with such investments. Transpower attempts to minimise capital cost while ensuring revenue is recovered.

9.2 Detection of possible solutions

Based on system studies, optimum investment requirements are identified by Transpower to determine possible grid solutions. These could be one of the following options:

- New Transmission line
- Application of FACTS technology
- Re-rating of existing circuits
- Utilisation of System Protection Schemes
- Rearrangement of substations.
- Creating new switching stations to balance power flow across lines.
- Reconductoring
- Use of technological advances, where they are applicable.

These solutions are assessed for their technical feasibility before they are progressed further for commercial discussions.

9.3 Final decision

Final decision is largely based on ability to recover revenue for the new investment via either regulated income or new investment contracts via customer contracts.

10. Norway

This chapter describes the planning approach for the Norwegian transmission system.

10.1 Detection of need for reinforcement

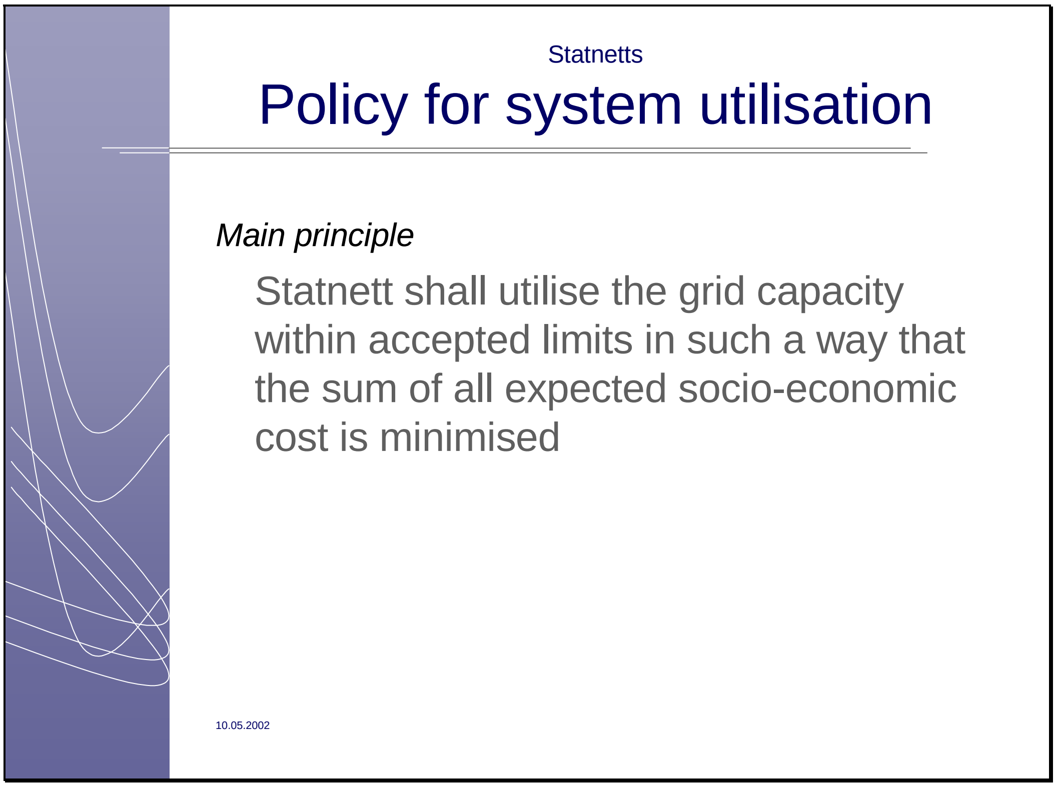
The need for new transmission capacity is normally caused by:

- increased consumption or
- new generation and/or new large consumers or
- new flow patterns due to deregulation and
- any combination of the first three.

If one of these events results in a violation of the operation/planning criterion or it is economical viable to do new investments, reinforcements usually are made.

Technical considerations

Security and adequacy are important fundamentals to all power system planners. In Norway Statnetts *Policy for System Utilization* describes the limitations of the system operation and planning.



The policy's

Accepted limits

1. Safety for personnel shall not be reduced
2. Assets shall be loaded within determined capacity limits, short term overloading included.
3. The consequences of an outage shall not be unacceptable:
   a) A single outage shall not cause an interruption of more than 2000 MW
   b) A single outage shall not cause more than 1000 MWh of energy not supplied
   c) The supply shall be restored within 2 hours
   The supply to radial connected consumers/grids shall be restored within 4 hours
   d) A supply node in the main grid shall have maximum 2 interruptions per year (measured as an average over 5 years)
4. After an interruption of consumption the grid shall be operated in such a way that the risk of one more interruption is minimised until
   a) The fault analysis has revealed the cause of the interruption
   b) Necessary corrective actions have been done, and normal operation is restored

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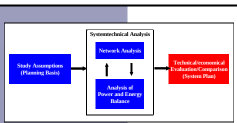
Economic considerations

As a consequence of the system utilisation policy it is important to know the cost/benefit of the different factors in the socio-economic cost/benefit analysis.



System Planning
Cost/benefit Analysis

- Socio economical evaluation

Socio economic cost/benfit criteria:

NPV > 0

NPV : The Benefit in Net Present Value of the Reinforcement Solution in proportion to the Reference Solution

Net Present Value (NPV) of a reinforcement solution in proportion to the reference Solution:

$$\mathbf{NPV = -\Delta I - \Delta O - \Delta E + \Delta B + \Delta L - \Delta D - \Delta S}$$

Δ-cost/benefit-elements: Net Present Value elements in proportion to the reference-solution

Cost-elements

Technical costs:
ΔI : Investment cost, i. e. investment-cost, reinvestment-cost of the reinforcement solution.
ΔO : Operation- and maintenance cost
ΔE : Environmental cost The cost of the impact the reinforcement project has on the nature, fauna, people and properties. The environmental cost is often very difficult to estimate.

Systemcosts:
ΔB : Bottleneck costs (Congestion Costs) (ΔB: the benefit of reduced bottleneck costs)
ΔL : Cost of hydrological and transmission losses (ΔL: the benefit of reduced costs of losses)
ΔD : Disruption costs, i. e. the cost of non-planned disruptions
ΔS : System protection costs, i. e. the cost of planned load- and production-interruptions, automatic actions initiated by critical contingencies or system conditions.

Δ-cost/benefit: Net Present Value of cost/benefit in proportion to the reference-solution

System Planning
Methodology

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The socio-economic equation as stated above is in fact both the operation and the planning criterion for Statnett. A positive NPV according to the above equation is mandatory for Statnett to make new investments. Hence it is important to be able to quantify the different factors in the equation where congestion costs and costs related to energy not supplied are the elements which are most difficult to estimate. Both having a high degree of uncertainty connected to them.

10.2 Detection of possible solutions

When making investments it is important to know that all (most) uncertainties are included in your analysis. In the planning process Statnett uses scenario techniques (2-3 scenarios with additional sensitivities) to cover the uncertainties.

Possible solutions are then detected, by using outage analyses and “engineering judgement”. The most promising of these possible solutions are then being subject to a full socio-economic evaluation.

10.3 Final decision

The best socio-economic solution that fulfils the ”system utilisation policy” is then chosen. If there are great uncertainties about environmental aspects/costs or licensing aspects more generally, especially for OH transmission lines, we often present at least two solutions when applying for license to build and operate new assets.

Final investment decision is made when we have been granted license to build from the authorities.

11. Portugal

Rede Eléctrica Nacional (REN) is responsible for establishing the expansion plans for the transmission network, which are presented for Regulator approval. The current network subject to transmission planning process includes all 400, 220, 150, 132 kV (residual) levels as well as the associated interfaces with generation and distribution including, in this last case, the dimensioning of the step-down substations and their transformers.

REN's Transmission Planning usually deals with a number of uncertainties such as the location and size of generating plants, load growth, fuel prices, capital costs, and regulation. Horizon planning and staging methodology is considered to be suitable to be used in long term planning.

REN's Transmission Planning Division considers a number of plausible scenarios covering credible future events that may prove to be critical to the transmission requirements and, in that way, reduce the risk associated with a planning decision.

11.1 Detection of need for reinforcement

The steps that are undertaken under the present planning philosophy for the detection of need for both system reinforcements and additions are based on the following:

- Data gathering both from a "System Generation Plan", issued by the Ministry of Economy, demands for new connection points from the consumers, (distribution supply their load forecast) and inclusion of future IPP connection points and their expected number and geographic location.

- Network simulation according to key planning criteria. These include adequate:

  1 - Voltage levels under normal and contingency situations
  2 - Loading limits for lines and transformers
  3 - Short-circuit capacity
  4 - Transient stability limits
  5 - Levels for harmonics, flicker and unbalance

- Systematic review of system performance and operation for:
  1 - Detection of congestion problems and network inadequacy.
  2 - On-going project implementation of transmission facilities

This general procedure is followed by the detection of reinforcements needs in the medium and short-term. These reinforcements depend not only on technical and/or economic considerations but also have to be coherent with strategic long-term options.

Technical considerations
A number of deterministic scenarios covering credible future events are used for both adequacy and security assessment.

The criteria include the steady state analysis as well the establishment of n-1 contingency tests for any single circuit, double circuit lines of more than 35km and all relevant circuits close to important urban areas of Lisbon and Porto. Short-circuit analysis and transient stability tests are also carried out for system assessment. When the level of uncertainty, regarding a local decision, is high, some sensitivity studies complement this general approach.

Economic considerations
Economic justification of system reinforcement or additions is based on positive net-present value. In this process alternative solutions are taken into account and compared in terms of their cost (investment, operation and maintenance) and their benefits (transmission losses and energy not served reductions).

This cost-benefit analysis is carried out and, when relevant, complemented with probabilistic chronological simulation of system behaviour along a certain period (typically a year). The process decision is then complement with system performance average indices like 'Expected Energy Not Served' and 'Loss of Load Probability'.

11.2 Detection of possible solutions

Alternative solutions for comparisons are analysed considering several issues and depending on the type of reinforcement one is faced with. For example, the location of new step-down substations is made in conjunction with the distribution company and the integration of future generator plants is made in accordingly with a system generator plan. Long-term transmission grid structure evolves several factors such as assessment of new technologies, consideration of future cross-border lines as well environmental issues.

11.3 Final decision

A 'Transmission Network Investment Planning' for the next 10 years (although only the next 6 years are the formal Plan, for which the projects are defined in detail) is subjected to approval of the Regulatory Entity, every two years. In the intermediate year, some adjustments are made. The schedule of system reinforcements is finally tuned in a yearly base taking into account the effective degree of project implementation and possible budget constraints that might exist in the short-term period.

In addition to the presentation of this approach, the Transmission System Operators of the Portuguese and Spanish Power Systems (REN and REE) are involved in the reviewing of criteria and planning procedures, as well as common proposals for grid expansion, within the ongoing implementation of the Iberian Power Market (MIBEL).

12. Spain

Within the Spanish Power System, Red Eléctrica de España (REE) is the Transmission System Operator, responsible for proposing the grid expansion plans to the regulator. The current area subject of transmission network planning is the Spanish peninsular system at the levels of 400 kV and 220 kV, as well as the corresponding interfaces with generation and distribution. The regulation concerning the extra peninsular systems is being developed, being likely that REE undertakes this role.

The planning approach may be synthesised as the detection of possible needs for “basic” reinforcement (to identify the structural needs justified in the most likely scenarios), followed by a selection based on a techno-economic evaluation of the candidate solutions and a further identification of potential reinforcements derived from additional economic savings.

12.1 Detection of need for reinforcement

The detection of the need for network reinforcements is motivated from both technical and economic considerations, which are taken into account in a complementary way. Although the discrimination between technical and economic realms is rather complex, two steps may be recognised:

- the primary needs for reinforcements come mainly from technical considerations: they are aimed to guarantee the supply reliability, although they do not provide a high flexibility for market implementation
- the additional needs have a higher influence from economic considerations, since the main contribution is a more flexible and efficient behaviour of the power market

Figure 1 reflects the combination of both perspectives.

The technical and economic considerations are present in the evaluation of basic and alternative scenarios, in order to issue possible solutions which are combined in order to produce the resulting plans. The reinforcement needs derived from basic scenarios (more likely and more energy balanced) are considered prioritised, being the economic considerations introduced in order to chose the most efficient. The needs from alternative scenarios (more unlikely and more unbalanced) are weighted with the expected likelihood.

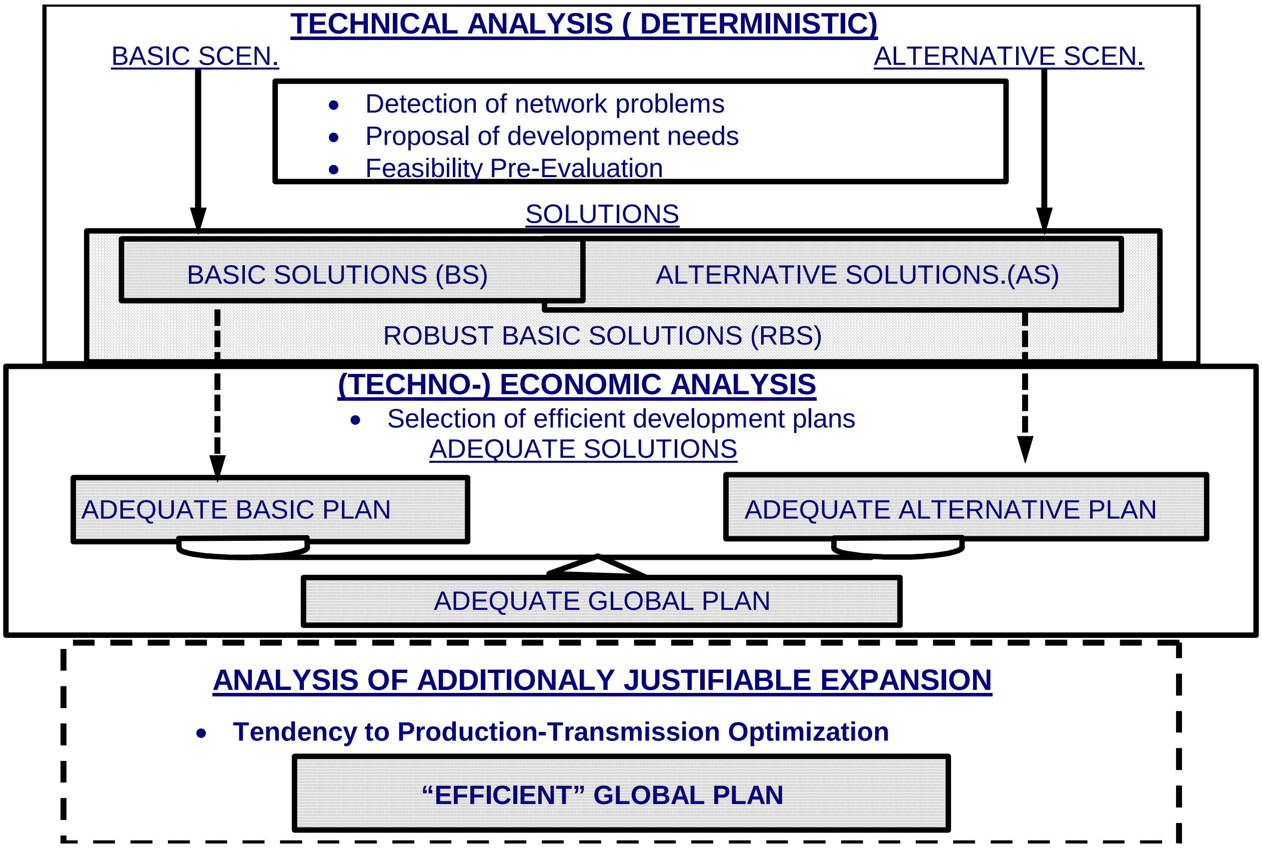

Figure 1 Overview of network planning framework

Technical considerations

The technical considerations are introduced through adequacy and security requirements, which are applied to the foreseen system scenarios in a deterministic way: some "representative" study cases are defined including winter and summer peak and off-peak conditions.

The adequacy criteria include the application of a set of prescribed contingencies (N-1 of grid branches and generators and N-2 of double circuit and of plant plus circuit) and the need to respect the control variable margins (maximum level of load flows and voltage within margin). Besides, the security standards include the assessment of the dynamic response of the system: angle stability after short-circuit contingencies in the main transmission lines or failure of the most significant generators, as well as voltage stability.

Economic considerations

The economic considerations are present in the choice of the most efficient plans that allow the accomplishment of the basic and alternative scenarios, with the discounted cash flow of the following attributes:

COSTS: Costs of Facilities (investment, operation and maintenance) **vs.**
BENEFITS: Savings in technical constraints, transmission losses and unserved energy

12.2 Possible solutions and Final decision

The preceding approach is applied to design the expansion plan for the medium term horizons (up to 10 years ahead), taking into account studies of long term horizons. Solutions include new facilities and the reinforcement of existing ones (uprating and upgrading policies are extensively applied). Other studies related to general technical choices (level of voltage, equipment definition, …) are also carried out.

In summary, there is a tendency of technical/economic optimisation with the following general priority:

- the basic needs -structural nature- derived from technical requirements always imply a solution; the economic considerations are included in order to choose the most convenient.
- the alternative needs -market efficiency nature- may require a solution depending on economic consideration.

The expansion plan results from the combination of the preceding needs in order to provide the highest efficiency.

In addition to the presentation of this approach, the Transmission System Operators of the Portuguese and Spanish Power Systems (REN and REE) are involved in the definition of coordinated criteria and planning procedures, as well as common proposals for grid expansion, within the ongoing implementation of the Iberian Power Market (MIBEL).

12.3 Analysis methods

Technical methods

The technical methods (those associated to support the planner in the technical perspective) are mainly supported by deterministic models, which are used to detect a technical need for system development. Thus, a number of scenarios (taking into account reference variation factors -season, day-time, hydro profile, labour/holiday, … -, as well as a number of sensitivity variants) are analysed and weighted in order to calibrate the expansion or reinforcement need.

In practical terms, general purpose power system analysis packages are used[4], as well as specific tailor-made subsidiary programmes and routines.

Probabilistic methods are used as a complement, by means of probabilistic load flow model (subsidiary programme based on a massive running of the general purpose tool). They take into account historic rates for the probabilities of forced outages of generation and transmission equipments.

Economic methods

The economic methods are both deterministic and probabilistic. The deterministic methods have been the traditional option to deal with economics and they constitute a simplified version; they are implemented through heuristic weighting of the prescribed scenarios/situation. The trend is to generalise the probabilistic methods by developing the corresponding ad-hoc models (SIMUPLUS[5]).

These models incorporate –besides the most traditional probabilistic functions associated to the equipment- price functions for every generation plant or group of plants, in order to evaluate the most efficient expansion plan based on the following balance:

COSTS: Costs of Facilities (investment, operation and maintenance, SEI[6])
vs
BENEFITS: Savings in technical constraints, transmission losses and unserved energy

4 General purpose package includes analysis models for simulation of the power system behaviour within static state [Load flow solvers, optimal power flow, linear models (DCLF)], dynamic state, short circuit calculations,...

5 See ”A new flexible Transmission Planning Methodology for Liberalised Electricity Markets: Models and Implementation within the Spanish Power System”. J.A.Sánchez, J.F.Alonso and others. CIGRE Conference. Paris, 2002. The presented tool –SIMUPLUS- has been implemented using General Algebraic Modeling Language (GAMS) and CPLEX optimisation package.

6 Socio-Environmental Impact, estimated according to heuristic fiogures for lines and substations.

WG37-30

Date: December 3, 2002

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Changing Legal and Financial Conditions in Europe, the Nordic Countries and Ireland

Appendix no 3
for
WG37-30: Network planning in a deregulated environment

Table of Content

1. The EU directive

The EU has issued a directive regarding common rules for the electricity single market. This directive formally came into effect on February 19, 1999, signifying that competition would be the norm, not the exception, for electricity trade and production in the EU countries together with Norway and Switzerland. The EU-directive lay down general rules for:

- how the electricity sector shall be organised, and how it will function
- how access to the market is achieved
- which procedures to use for establishing new generation
- how to operate systems

The EU directive allows a high degree of optional choice of how to liberalise. Each member state must fulfil the general rules stated in the EU-directive through national legislation, where special national interest can be specified. The authorities can order the electricity sector public service obligations regarding e.g. system reliability and environmental protection.

The EU directive specifies the unbundling between transmission and production in order to establish competition in the power production industry and a free choice of power supplier for the consumers.

Most of the countries within the EU have a single Transmission System Operator, whose overall task it is to be in charge of the operation, maintenance and if necessary the development of the transmission system and interconnections to guarantee the reliability of the system. The system operator has some authority in relation to the overall operation of the power system e.g. in relation to load shedding, prioritising RES-production, securing reserves and ancillary services.

Exchanges between interconnected systems have always existed, mostly used for ancillary services, reserves, and trade based on known bilateral contracts. In a liberalised environment anyone will have the possibility to trade on the market and the exchanges will be determined by the market price which is dependent on physical constraints in the transmission network and on the interconnections and on existing contracts and reservations for ancillary services.

In order for the system operator to be able to perform his/her activities, information from the market players is necessary. The system operators are obligated to preserve the confidentiality of information with commercial sensitive character.

In most of the EU member states, new production capacity is established through an authorisation procedure, which means that any company can apply for establishment of new generation. The establishment of new generation will be based on the companies' financial situation and by that the price for power. The regulator can specify criteria for reliability and environment which have to be fulfilled in the application for new generation. The future production capacity will be controlled by the function of the market and therefore, be more unpredictable.

In December 1997 the EU commission presented their white paper on renewable energy, in which a strategy and an action plan regarding promotion of renewable energy has been contemplated. The goal is to double the part of renewable energy to 12 per cent of the electricity consumption in 2010 in order that on an average the increase will be of 10 %. A directive on renewable energy is discussed in the EU. The discussion is based on the goals of the white paper and UN's Kyoto agreement.

In addition an EU directive on the assessment of the development regarding the environment of public and private projects is based on the assessment of each individual country on building new plants.

On July 1, 1999 a new organisation called the association of European Transmission System Operators (ETSO) was founded. The founders were Nordel, the Union for the Co-ordination of Electricity Transmission (UCTE), the United Kingdom Transmission System Operators Association (UKTSOA) and the Association of Transmission System Operators in Ireland (ATSOI).

1.1 The Nordic countries

The Nordic countries form a fully integrated multinational electricity market with one common spot market for physical power trade. The electricity market is called Nord Pool. The market area consists of the synchronously connected systems in Norway, Sweden, Finland and East Denmark plus West Denmark, which is synchronously connected to the Continent.

The electricity market in Norway was liberalised on January 1, 1991 followed by the markets in Sweden and Finland in 1996-1997 and finally Denmark in 1999. From the start of the liberalisation in 1991 the market has matured and grown into a fully competitive market including all consumers of electricity (in Denmark all consumers will be included in 2003). The consumers included in the market are free to choose their electricity supplier.

1.1.1 Organisation

The Nordic Transmission System Operators Fingrid (Finland), Svenska Kraftnät (Sweden), Statnett (Norway), Eltra (Western Denmark) and Elkraft System (Eastern Denmark) co-operate in Nordel (equivalent to UCTE). A "system operation agreement" that regulates the operation of the Nordel system does exist. This agreement is essential to make the infrastructure of the power market work. Furthermore the TSOs co-operate when investments in interconnections are necessary. Svenska Kraftnät and Statnett own Nord Pool.

The ownership and organisation of the main transmission grid is thus left to one TSO in Norway, Sweden and Finland and two in Denmark. There are also a number of regional network utilities and distribution network utilities which operate under the same legal and financial framework as the TSO's. The TSO's are appointed system responsible by the authorities.

The power systems in the different Nordic countries vary from 100 % hydropower to almost 100 % thermal power. Synergy effects between these systems have been utilised for many years. Liberalisation has made these effects even more visible.

1.1.2 Legal changes

The Nordel countries have during the last ten years had new Energy/Electricity Acts based on EU directives and national legislation. The new acts started the liberalisation process in each country. The following describes the most important legal changes.

Market considerations

A new task in the power system is considerations for the market function and the creation of competition.

The purpose of the Electricity Market Act in Finland is "… to ensure preconditions for an efficiently functioning electricity market so as to secure the sufficient supply of high-standard electricity at reasonable prices."

Similar purposes are stated in the other countries' legislation, but with different weight on the market considerations. For instance in Denmark the purpose of the electricity act is to ensure that the power supply is planned and carried through in consideration of reliability, economics, environment and consumer protection. Among other things the law must ensure an efficient use of financial resources and create competition on the markets for production and trade with electricity.

The EU background of the electricity acts in the Nordic countries is the same, but the national considerations result in different interpretations and purposes.

The competition has resulted in significantly lower energy prices. For profit-oriented power generating utilities this results in greater focus on cost efficiency to keep the profit up. Margins are lower which in turn makes volume even more important to generation and selling of electricity. A consolidation in the industry has resulted in fewer, but bigger utilities.

Unbundling

The legislation states that commercial activities such as production and selling of electricity should be separated from the transmission and distribution network monopolies. In Norway, as a result of this, the government decided to split their integrated power producer and transmission utility Statkraft, into two new utilities, Statkraft (power producer) and Statnett (transmission system operator). Similar actions are made in the other Nordic countries.

In a liberalised market, investment in new generation capacity is left to the market players, and is no longer a responsibility of the authorities based on a prognosis of future power demand.

The result of this is that practically no new generation capacity has been introduced in the Nordic countries. An exception is wind turbines, which from an environmental point of view has been built in Denmark and to some extent also in Sweden.

In the Nordic countries where hydropower counts for approximately 50 % of the generation capacity, the task of introducing new peak power capacity into the market has proven to be an essential and difficult question.

Experience from the market so far has shown that situations with high prices are to few to justify investment in new capacity. This winter both the TSO's of Sweden and Norway have found it necessary to buy peak power capacity and reserve capacity outside the spot market, to deal with the problem. To make sure that the market can handle this, it is important to introduce necessary incentives for investments in new capacity.

The liberalisation has thus introduced an uncertainty related to investments in new generation capacity, which together with environmental considerations are perhaps the most important factors relating to the planning and operation of the transmission system.

System reliability

The legislation recognises the need for someone to be responsible for the safety of operation and to secure the balance between generation and consumption of electricity.

In Denmark the system operator is responsible for the system reliability, but this is not specified in the legislation of all the countries. However history has shown that it is the transmission system operator who gets the responsibility. There is no evidence so far that the liberalisation has reduced the system reliability.

It is more important than how legislation impose different activities to the TSO's, that the transmission utilities shall serve both a market and ensuring the system reliability.

The market players have quite different incentives and demands of the system than was the case when reliable supply of electricity within each country was the only demand.

This can be summarised in what Statnett now recognise as their main goal *"to ensure an efficient power market"*. (There is not only one goal: the reliability in supply, the market and the environment is equally important to the planning).

Concession

For some activities a granted concession is needed from the authorities. Such activities may be building new transmission lines electricity transmission, the selling of electricity, foreign trade, etc.

The financial incentives are important for utilities to apply for concession (paragraph 1.1.3) and thereby important for the system reliability and market function.

Based on a decision to grant concessions impact on the environment is an important issue because the building of new power plants is subject to severe environmental requirements and some even to demands of implementing an assessment of the effects on the environment as a consequence of the EU directive.

The grid owner or network operator has an obligation to develop the power network for which they have been granted concession.

For the utilities being granted "network concession", there is usually an obligation to **connect** new customers to the network (against a reasonable compensation).

1.1.3 Financial changes

The income of the system operator is today the network tariffs, which for instance covers operation, maintenance and new equipment. The authorities regulate the network monopolies, financial frames to make sure that the monopolies are efficiently and sufficiently operated and that the tariffs are reasonable. The Nordic regulators have chosen different ways of achieving this.

In Finland and Sweden the network monopolies (including the TSO's) can charge the customers a reasonable compensation for using the network. In case of a dispute there are different ways of handling this.

In Denmark and Norway the financial regulation of the network utilities are treated differently. In these countries each network utility is given a revenue cap, which must cover all costs including new investments. This revenue is reduced annually by introducing a requirement for productivity growth. This revenue represents the sum of all tariffs which the utility can collect, and utilities which are able to reduce their costs will get higher profits.

The financial frames include income and investment frames and company finance and give both incentives and limits in establishing new equipment.

The financial regulations give incentives to reduce costs and improve efficiency which have resulted in a businesslike behaviour also among the network utilities. Cost reduction programmes are introduced to increase efficiency and profit, and benchmarking is used to identify improvement potentials.

Before the liberalisation in Norway a cost reduction of 30 % was regarded as reasonable for the network utilities. Later estimates identify even higher potentials.

1.1.4 Environmental changes

According to the Kyoto protocol the European Community and the EU member states must reduce their annual discharge of green house gasses by 8 % between 2008-2012 compared to the situation in 1990.

The Kyoto agreement implies the opportunity to apply a number of international mechanisms in order to meet these reduction requirements. The three so-called Kyoto mechanisms include international trading of quotas (IET), Joint Implementation (JI) and Clean Development Mechanism (CDM).

According to the white paper on renewable energy from the EU commission Denmark is the only country with official goals of the pro rata increase in renewable energy until 2010. All the Nordic countries will follow up on the climate convention and the Kyoto Protocol. The plan is in particular based on a increase in windpower in the Nordic countries.

The regulation of renewable energy is not a result of the liberalisation, but has great importance for the operation of the market and for how large a part of the market has been regulated.

1.2 The Irish Electricity Industry

The Electricity Supply Board (ESB) was established in 1927 as an integrated electricity generation, transmission and distribution utility. With a peak demand today of approximately 4000 MW, generation availability of approximately 4400 MW, demand growth around 6% over the past five years and a deficit in transmission infrastructure have all contributed to increased difficulties in operating the transmission system.

1.2.1 Regulation

In 1999 the Government set up an independent Commission for Electricity Regulation (CER). The main functions of the CER are as follows:

- to oversee the introduction of competition into the electricity sector
- licensing the generation and supply of electricity including the issue of the Transmission System Operator (TSO) licence
- issue authorisations for the construction of generating stations
- oversee the provision of information about access to the Transmission and Distribution systems and related charges
- Use of system tariffs to be determined by the TSO and regulated by the CER

1.2.2 Legislation – Establishment of the TSO

In 2000 the Government issued a Statutory Instrument setting out the rules for establishing the Transmission System Operator (TSO) as a separate, independent, State Company set up with the purpose of meeting the requirements of Directive 96/92/EC for independent operation of the transmission system. The main functions of the TSO are as follows:

- TSO to have operate and control the transmission system necessary to comply with its functions under the Directive 96/92/EC
- provide access to the transmission system for independent power producers and suppliers
- planning the development of the grid
- provide public information on access to the system and system development

Note that the ownership of the transmission system assets will continue to lie with the ESB and not the TSO.

1.2.3 Market

The electricity market in Ireland is a day-ahead bilateral trading system where independent sector parties are provided ‘top-up’ and ‘spill’ imbalance services from ESB under tariff rates set by the Regulator. Generators nominate initial positions from which they are dispatched from, unless adjusted to meet system constraints, and then trade final contract positions ex-post before settling imbalances.

Initially 28% of the market (mostly commercial / industrial electricity users) is eligible to choose supplier. Independent generators and suppliers are provided access to the market to serve the requirements of these eligible customers. There is full market access for renewable power suppliers. It is likely that the eligible market percentage will grow with 100% eligibility a future possibility.

Market participants can trade on the inter-connector with Northern Ireland by purchasing capacity in an annual auction or in a daily market.

1.2.4 Transmission Network Access

Users connecting to the transmission system are charged for the provision of the physical assets that provide the connection and a ‘use of system’ charge for provision of access to transmission system infrastructure and services.

Generators are not directly charged for transmission system reinforcements that may be required to allow export of their power. Because of the long lead times often associated with the provision of transmission infrastructure, Generators have a degree of ‘firm’ access to the transmission system prior to reinforcements being completed.

CIGRE WG37-30

Date: April 5, 2001
Case no.: 2586
Doc.no.: 100045
Reference: RBI/AKN

CIGRE 37-30

Network planning in a deregulated environment

Questionnaire

INTRODUCTORY REMARKS

This questionnaire is a part of the preliminary work by Cigre working group WG37-30. The overall objective of WG 37-30 is to analyse the need for development of medium and long-term transmission planning methods in a deregulated environment. The transition to a deregulated environment in the electricity industry inevitably changes the traditional way of planning electricity networks by decentralising the planning of transmission and generation and thereby introducing new uncertainties and new risks to be managed. The group started work in April 2000 which we expect to complete by April 2002.

In order to carry out an exhaustive and significant analysis, identification of key issues is seen as a necessary prerequisite. A survey to elicit information on how network planners operate in different regulatory environments has been identified as an efficient way for identifying these key issues. The aim of this questionnaire is to collect this information which will enable the work of the group to continue.

On the questionnaire you will find a number of multiple choice questions which you should be able to answer rapidly. In the main you should be able to tick one box, if however you need to tick more than one box, please do so.

Where possible, additional information in the spaces provided in your response would be useful.

The questionnaire can be completed by hand or electronically and returned by email to:

rikke.bille.joergensen@eltra.dk

or by ordinary mail to:

Eltra
att. Rikke Bille Jørgensen
Fjordvejen 1-11
7000 Fredericia
Denmark

A questionnaire completed on behalf of the Transmission Business of the National Grid, who own and operate the 400kV and 275kV network in England and Wales, is attached for your information. This is accompanied by a Case Study supplied by Eltra, the transmission company for Western Denmark.

I GENERAL INFORMATION

1. Name and adress of company:

   Name:____
   Adress:____
   Country:____

2. Name and role of contributor:

   ____

3. Is your company the system operator for the entire country?
   ☐ Yes ☐ No

   If No, which part of your country do you cover?

   ____

   What are the names of the other transmission system operators in your country?

   ____
   ____
   ____

4. At what voltage levels do you operate?

   ____

I.1 Rules and organisation

1. For how many years has the electricity system been deregulated?

< 1	1 – 5	6 – 10	11 – 15	> 15

2. Is your company a:
   ☐ Transmission network owner and operator (TSO)
   ☐ Independent system operator (ISO)
   ☐ Other (please describe)

   ____

3. Are the transmission activities fully separated from generation?
   ☐ Fully independent
   ☐ Managed independently within the same company ☐ No

4. Does your company own the transmission network?
   ☐ Yes ☐ No ☐ Partly

5. What is the company ownership?
   ☐ Public ☐ Private ☐ Other (please describe)

6. Does a regulatory authority exist?
☐ Yes ☐ No

If yes, is the regulatory authority:
☐ Government body ☐ Independent public authority ☐ Other (please describe)

7. Does your company have to comply with rules governing transmission network access?
☐ Yes ☐ No

8. Does your company have an obligation to offer terms for access to the transmission network?
☐ Yes ☐ No

9. Is the level of your transmission business income regulated?
☐ Yes ☐ No ☐ Other (please describe)

I.2 Definition of transmission system

1. What are the primary activities of the company?
☐ Network planning ☐ System maintenance and construction
☐ System operation ☐ Other (please describe)

2. Is there a legal definition of the term transmission?
☐ Yes ☐ No

If yes, what is the definition?

3. Are there exceptions to this rule?

Assets which are no longer considered to be transmission?
☐ Yes ☐ No

Assets which are now considered to be transmission?
☐ Yes ☐ No

4. Has the definition of the term transmission been reviewed since deregulation?
☐ Yes ☐ No

5. Has the definition of transmission been based upon consideration of:

Asset ownership / charging arrangements?	☐ Yes	☐ No
Treatment within the planning process?	☐ Yes	☐ No
Role of the SO?	☐ Yes	☐ No
Organisation of network maintenance?	☐ Yes	☐ No

Other?

____

II - PLANNING APPROACH

II.1 Network planning fundamentals

Data exchange

This covers the exchange of data between your company and generators, distribution companies and suppliers.

1. How is technical data exchanged?
☐ Contractual ☐ Voluntary ☐ Other (please describe)

2. How often is technical data exchanged?

3. How do you manage to maintain the appropriate level of data confidentiality? (please can you provide a short example)

4. What information is your company required to publish in relation to the development of the transmission system?

5. What information is your company required to publish in relation to the opportunities for access to the transmission system?

____
____
____
____

Load

6. What basis is used for historic load data?
☐ Customers' measurements ☐ Own measurements ☐ Other (please describe)

____

7. Who performs the load projection?
☐ Customers ☐ Own company ☐ Other (please describe)

____

8. Do you take load management into account? (This is where large customers respond to price signals to reduce their load at time of system peak.)
☐ Yes ☐ No

Generation

9. Do you as the network planner manage the generation openings and closures?
☐ Yes ☐ No

10. From where do you get generation market information?
☐ Electricity market reporters ☐ Participants directly
☐ Other (please describe)

____
____
____

11. Do you take the following information into account in assessing the opening of potential new generation?

Financial security	☐ Yes	☐ No
Project type (eg gas-fired, combined heat & power, renewable)	☐ Yes	☐ No
Planning permissions and/or statutory conditions	☐ Yes	☐ No
Access to fuel supply	☐ Yes	☐ No
Power purchase agreements	☐ Yes	☐ No
Location with respect to transmission charges	☐ Yes	☐ No

12. Do you take the following information into account in assessing the closure of existing generation?

Financial assessment	☐ Yes	☐ No
Company strategy	☐ Yes	☐ No
Project type (eg nuclear, coal)	☐ Yes	☐ No
Access to fuel supply	☐ Yes	☐ No
Ancillary services income	☐ Yes	☐ No
Age	☐ Yes	☐ No
Thermal efficiency	☐ Yes	☐ No
Emissions	☐ Yes	☐ No
Location with respect to transmission charges	☐ Yes	☐ No

13. From where do you get information on the opening and closure of dispatchable generation?
☐ The producer ☐ Own assessment ☐ Other (please describe)

14. From where do you get information on non-dispatchable, embedded and renewable generation?
☐ The producer ☐ Own assessment ☐ Other (please describe)

15. Are there rules for notification of closure of generation capacity?
☐ Yes ☐ No

If yes, please describe

16. Are there rules for notification of establishing new generation capacity?
☐ Yes ☐ No

If yes, please describe

17. Do established generators have continuing access to the transmission system (ie existing generation may not be constrained by new entrants without financial compensation)?
☐ Yes ☐ No

II.2 Network planning criteria

1. Who is responsible for authorisation of the network planning criteria and their mode of application?
☐ Own company ☐ Regulator ☐ Other (please describe)

2. How many years ahead do you plan the transmission network?

3. Who performs the network studies? (load flow, transient & fault analysis)
☐ Own company ☐ Consultants ☐ Other (please describe)

4. What are your network planning criteria based upon?

Technical requirements for:
☐ Transmission capacity ☐ Voltage ☐ Stability
☐ Frequency ☐ Other (please describe)

System performance indices:
☐ Loss of load probability (LOLP) ☐ Other (please describe)

Economic rationale:
☐ Constraint costs ☐ Cost of loss of load
☐ Environmental costs ☐ Transmission losses ☐ Other (please describe)

Others:

5. What criteria do you use for your economic decision making?
☐ Discounted Cash Flow showing a positive Net Present Value
☐ Other (please describe)

6. Contingency criteria.
If you assume that there are no planned outages on your system at winter peak, what unplanned outages do you cater for?
☐ Any 2 circuits and/or generators
☐ Double circuit lines and single circuits
☐ Single circuits only

7. In addition, do you consider your ability to take planned outages through the year?
☐ Yes ☐ No

8. Do you have special planning criteria for cross-border lines?
☐ Yes ☐ No

If yes, what?

9. How is dispatchable generation treated in the network planning criteria?
☐ Loss of any single generating unit ☐ Other (please describe)

10. Do you have special requirements regarding the quality of supply?
☐ Fault level ☐ Harmonics
☐ Unbalance ☐ Other (describe)

11. Have the planning criteria been changed after deregulation?
☐ Yes ☐ No

If yes, what are the key changes and why?

II.3 Decision Making

1. On what basis is the final investment decision made?
☐ Technical requirements (ie there is no need to economically justify the increase in capacity except in choosing the most efficient scheme)
☐ Economic justification
☐ System performance indices ☐ Environmental demands
☐ Other (describe)

___

___

2. Who approves the investment decision?
☐ Regulator ☐ Own company
☐ Market participants ☐ Other (please describe)

___

3. Have the investment decision criteria changed after deregulation?
☐ Yes ☐ No
If, yes, explain how and why:

___

___

___

___

4. Who finances the network investments?
☐ Own company ☐ Market participants ☐ Other (please describe)

___

___

If own company, are you able to recover these costs automatically (please describe)?

☐ Yes ☐ No

___

___

___

5. Are there different investment criteria for cross-border investments?
☐ Yes ☐ No

If yes, what are they?

___

___

___

6. Has deregulation altered the level of network investment?
☐ More investment ☐ Less investment ☐ No change

III UNCERTAINTIES

1. What are presently the most significant uncertainties in the development of your transmission system?

Load uncertainties:

☐ Growth
☐ Location
☐ Annual variations
☐ 24 hours variations
☐ Other (please describe)

Generation uncertainties:

☐ Costs
☐ Physical location of new plant
☐ Closure of old plant
☐ Unpredictable production
☐ Availability factors
☐ Other (please describe)

Regulatory uncertainties:

☐ Transmission pricing framework (regarding the construction of new lines)

☐ Pool Pricing Rules
☐ Other (please describe)

Planning and environmental uncertainties:

☐ Planning & consents (regarding construction of new lines)
☐ environmental legislation

☐ Other (please describe)

Other uncertainties (please describe)

2. How are the uncertainties modelled in the planning process?

☐ No modelling
☐ Scenario analysis
☐ probabilistic modelling
☐ Other (please describe)

3. Describe how uncertainty is incorporated into investment decision making process?

____
____
____
____
____
____

IV CONCLUSION

We would be grateful if you could consider whether you have a case study which you could share with the working group highlighting what you consider to be a key issue arising from transmission network planning in a deregulated environment. Please note that this is purely optional.

A case study should ideally cover one page, with the following four headings:

Problem
Consequence
Action
Key Issues

Thank you for your time and co-operation in completing this questionnaire. Please indicate whether you would like to receive a copy of our final report.

☐ Yes ☐ No

List of respondents

Australia	Transend Network Pty Ltd
Australia	ElectraNet SA
Australia	Victorian Energy Networks Corporation (VENCorp)
Australia	Power and Water Authority
Australia	Western Power Corporation
Belgium	ELIA
Denmark	Eltra
France	Gestionnaire du Réseau de Transport d'Electricité (RTE)
Germany	DVG Deutsche Verbundgesellschaft e.V.
Ireland	ESB (Electricity Supply Board) National Grid
Italy	Gestore Rete di Trasmissione Nazionale
Japan	Kansai Electric Power Company
Jordan	National Electric Power Company
New Zealand	Transpower New Zealand Ltd.
Norway	Statnett SF
Portugal	Rede Elétrica Nacional, REN SA
Quatar	Qutar general electricity and water corporation (Kahramaa)
Romania	Transelectrica – Romanian grid company
Spain	Red Életrica de España
United Kingdom	National Grid Company
USA	Michigan Electric Transmission Company