PLANNING CRITERIA FOR FUTURE TRANSMISSION NETWORKS IN THE PRESENCE OF A GREATER VARIABILITY OF POWER EXCHANGE WITH DISTRIBUTION SYSTEMS

JOINT WORKING GROUP CIGRE/CIRED C1.29

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PLANNING CRITERIA FOR FUTURE TRANSMISSION NETWORKS IN THE PRESENCE OF A GREATER VARIABILITY OF POWER EXCHANGE WITH DISTRIBUTION SYSTEMS

CIGRE/CIRED JWG C1.29

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Planning Criteria for Future Transmission Networks in the presence of a greater variability of power exchange with distribution systems

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EXECUTIVE SUMMARY

Our world is changing. In many countries traditional fossil fuel power stations are closing due to cost, inefficiencies, or environmental policy. In many developing but also developed countries we are expecting electricity usage to increase. Coal and gas is expected to become less prevalent, with more than 15% of electricity being produced from renewable means by 2020 in many countries and much higher percentages in many small and large countries globally. The global recession has affected overall power demand in some countries, but electrification of domestic heating and transport is expected to contribute to an increase in energy demand from the early 2020s even there. There are many scenarios to be considered, each one predicting different growths in renewable energy, but all predicting that renewable energy will play a growing part of the electricity system which in turn becomes a growing part of the energy system.

Much of this growth is currently being seen in distribution networks. Smaller scale wind farms, solar farms and domestic (household) energy sources are contributing to a changing way in which the Electricity Transmission and Distribution system works. This decentralised energy, often variable and not well controllable, needs an ever-sophisticated platform to economically deliver energy to consumers.

This results in increasing challenges facing the current electricity system associated with the increasing penetration of Distributed Energy Resources (DER) and the importance of maintaining the security and quality of supply during varying operational conditions (e.g. failures in embedded generation, distribution network faults, interconnector non-availability) or in specific periods of day, week or year (e.g. excess generation in non-peak or maintenance periods).

To date conventional demand planning criteria has been initially based on very little use of DER, with small evolutionary modifications made to planning standards to cater for distributed resource growth.

Using historical data relating to Transmission System Operators (TSO) to Distribution System Operators (DSO) net power exchange in order to plan the evolution of transmission systems may eventually lead to under-investing in the need to reinforce the High Voltage (HV) network, and may even impact on system security. Whilst at the same time, designing the system in order to be able to supply the full transformation power installed could give rise to unacceptable over-investment.

Significant increase in penetration of DER, use of interconnection with other grids, and utilisation of smart grid technologies makes distribution and transmission system planning more challenging than in the past.

In this context, a Joint Cigré-CIRED Working Group (JWG), C1.29, has investigated the growth of DER and highlighted the implications for transmission and distribution planners, the output of which is this brochure: It details where historical methods of data exchange may be inadequate, and further, what future exchanges of data between transmission and distribution system operators may be required to create a more robust demand planning criteria for electricity grids.

The brochure begins with an assessment of the most common, traditional and "state-of-the-art" methodologies for Transmission planning taking into account the presence of DER and comparing them in terms of complexity, accuracy, system security and cost-efficiency. This task involved collecting information about most common practices adopted by TSOs with specific regards to the information that interfacing DSOs presently bring to support Transmission network planning.

A significant section of this brochure is devoted to defining conceptual criteria for planning of transmission systems connecting distribution systems in an instructive possible extreme case of future conditions, i.e. with zero or negligible TSO-DSO active power exchange in ordinary conditions. That section specifies presently unavailable data or measurements which are crucial for this for good system planning under such conditions.

This task involved collecting information about tendencies in transmission network planning from chosen TSOs and DSOs, relevant Cigré-CIRED papers and other publically available literature and carrying out a methodical exercise using a SWOT matrix coupled with a GAP description in order to characterise existing methodologies in terms of adequacy towards future-proof scenarios, and provide recommendations for future work.

The mentioned extreme scenario could get closer if DSOs influence previously unrestricted behaviours of connected users, as well as operating their own flexibility resources, to manage their systems in an unprecedented and possibly more efficient manner, optimising operation, minimizing losses, and also limiting power exchange between HV and

MV systems. This could only work if and where embedded generation would be able to provide all the energy the loads require under ordinary conditions, and if and where the load profiles of energy consumption and injection would be equal through use of strong demand response activities and storage facilities. In this future 'extreme' scenario, where the power exchange between HV and MV could be strongly affected by actions carried out by the DSO, the sizing of the Transmission/Distribution interface could be increasingly inefficient if only historical demand data were used for system planning.

The review of data exchanged between TSO and DSO shows some common practice in the types of information exchanged (embedded generation capacity, new connection capacity, number and size of transformers) although there is some data that is inconsistently shared such as new connection fuel type and transformer reverse power flow capability. Our research showed that only two thirds of TSO's have a 'live' view of currently generating renewable energy, and although three-quarters of TSO's have the capability to curtail embedded renewable generation, the quarter that don't have this ability are ones with currently high renewable penetration.

As a general rule, DSOs are mainly focussed on the service they need to provide to their end customers and so rely on the TSO to ensure overall system stability and reliability. When carrying out investment planning, it is logical that the cost of re-dispatch and cost of curtailment of DER are not considered, as DSOs are not normally permitted to perform these activities. In general, all DSOs show they take into account the economic aspects of regulation, in the sense that if incentives/penalties of any kind are foreseen, they are also adopted as investment evaluation cost elements. The extent, and the way in which DSOs play their role in managing DER varies in different utilities, and in different countries, mainly according to the existing regulations.

The brochure concludes that if current planning methodologies continue, there is likely to be under-investment in the TSO-DSO interface in order to make it 'future-proof'. Current methods of predicting the future utilise scenario modelling or probabilistic methods which look to deal with the uncertainty in those models and minimise any impact to the consumer. These however require little additional collaboration between the DSO and TSO.

Significant additional data is required to be shared between TSO and DSO in order to understand the future requirements of the interface. There needs to be an incentive for the DSO to 'manage' their network to minimise the impact on the TSO, especially in the context of a future scenario where there is negligible active power transfer due to large amounts of distributed energy. Current methods of 'gain share' could prove a useful incentive for the DSO and TSO to work together to share data and minimise investment in the TSO network.

INTRODUCTION

Scope

The scope of this technical brochure is to highlight the impact of an increased level of Distributed Energy Resources (DER) at Medium Voltage (MV) and Low Voltage (LV) levels on network steady-state planning at Higher Voltage (HV) levels.

More specifically, the document will analyse several planning techniques, currently adopted and/or in the process of delivery, verifying their adequacy to guarantee secure and affordable network planning within an "extreme" reference scenario in which all electrical sub-systems, represented by MV busbars, are constantly kept balanced by DSOs, thus maintaining both active and reactive power exchange at the boundary points between MV and HV networks at a zero value.

Contents of the Technical Brochure (TB)

The following topics are presented within the technical brochure:

Chapter 2 contains a short overview of a possible "extreme" scenario including huge Renewable Energy Sources (RES) growth and increased level of control over DER.

Chapter 3 contains a brief review, in terms of algorithms and datasets, of most common practices for HV steady-state network planning.

Chapter 4 contains a review of potential adequacy of most common planning practices within the predefined "extreme" scenario and analysis of major gaps in terms of algorithms and datasets.

Chapter 5 contains a brief review of most promising innovative methodologies for HV steady-state planning, from current practices adopted by chosen TSO's and those resulting from publically available papers presented in international brochures.

Chapter 6 contains a review of potential adequacy of innovative planning methodologies within the same predefined "extreme" scenario.

Chapter 7 contains the conclusion, identifying some best practice in terms of planning standards, and critical data information that needs to be exchanged between DSO and TSO.

Problem Setting

HV system planning, determines the most cost effective solution to changes in the network, caused by various sources (generation, demand, connections etc.) to ensure system security and continuity of supply. Planning commonly looks at future scenarios, and tries to predict trends in order to minimise costly last minute interventions. This technical brochure, focuses on the changes due to large levels of distributed energy being connected at the MV and LV levels (wind, solar etc.), and questions what should future planning criteria be to minimise the risk of under or over-investment and maximise system security.

The analysis to be performed includes both steady state calculations and transient simulations. This brochure will focus exclusively on steady-state calculations, which are run in a similar manner both in HV transmission and distribution networks.

Steady-state HV planning is generally done by performing a series of load flows, each one related to a specific condition in terms of network configuration, load absorption and generation injection. Simulations are run to verify if, and in which condition, network parameters go outside the prescribed boundaries (e.g. maximum thermal capacity of feeders, voltage drops in nodes, short circuit currents protection, and so on). In case of violations, interventions must be defined, and scheduled according to the year in which the criticalities arise, to maintain/restore acceptable conditions.

The methodologies currently used to perform this kind of HV planning differ in terms of algorithms applied and datasets used. Deterministic as well as probabilistic representations are adopted to elaborate the input data in order

to determine consumption and generation in HV nodes to be used in load flow calculations. The contingencies that are analysed to assess the most critical yet reasonable system conditions may imply different levels of severity in terms of unavailability of components, ranging from [N] to [N – X] and taking into account fault interdependencies and, in some cases, probability. Strategies in investment selection and prioritization criteria may also differ, – depending on regulatory framework and technology roadmaps.

However, most methodologies have something in common: the source of the data that is used to perform the simulations.

In fact, the HV lines in the case of steady-state planning are represented by their electrical characteristics and they depend on their physical as well as dimensional features. Therefore, no substantial differences exist under this respect while comparing different methodologies.

The most important input data for load flow calculations is, without any doubt, represented by load and generation in the HV nodes. The main, and more or less universally adopted, assumption to get an estimation of their actual values and their future trends is that, for a given HV node, the collective behaviour of the network users which are connected to the embedded MV and LV systems is the (deterministic or probabilistic) sum of their unrestricted individual behaviours.

This interpretation, assuming that historical data represents the "natural" combination of past behaviours and assuming that no significant changes are going to happen in the planning period, allows the use of the same kind of historical data and the extrapolation of their time series according to sophisticated forecasting techniques. This allows a system planner to perform accurate evaluations of HV network adequacy for future conditions. In so doing, the effect of the increase of the number of connected users as well as their change in behaviour is taken into account. This is because the measured values capture both increase/decrease of connected customers and increase/decrease of individual consumption/injection.

The mere increase in the amount of non-dispatchable generation connected to MV and LV networks, though significant in quantitative terms, doesn't really challenge this paradigm, as this kind of contribution can still be managed in a conventional way. As an example, photo-voltaic (PV) generators can be quite reasonably regarded as "negative loads". However, these negative loads are less predictable in that there is normally no direct monitoring of their output and they can vary from zero to close to maximum output in a relatively short space of time.

In this (still conventional) case, "collective" load and generation trends can be estimated on the basis of historical data, after a process of determining the split of generation and load contribution values which have been found in the past. The number of simulations to be run increases, as the worst possible cases result from a higher number of intersections between load and generation scenarios, but no real change in the underlying model appears.

The same approach applies in a case where, calculated instead of measured input data, for Real Power and Imaginary Power (P, Q) are used. The underlined assumption is that a collective behaviour results from a mix of unrestricted individual behaviours and therefore the process of determining load and generation values for load flow calculations essentially consist of defining a set of rules (e.g. in terms of contemporaneity coefficients, etc.) to add up all load and generations reference data.

Another approach, very cautious and not based on historical measured data, implies assuming that the HV network must be verified in a condition in which every HV node is loaded up to the extent in which the HV/MV transformer is fully charged. This is a very conservative methodology but at the same time, it cannot be applied without also considering the possibility that a HV/MV transformer can at one time become overloaded, needing replacement.

Both these approaches assume no significant degree of control is exerted on distributed resources by the relevant DSO; however, this condition is typical of traditional distribution system management and will very likely change in the near future.

No doubt this change of paradigm will offer great opportunities to improve distribution network operation and will bring many benefits to the electric system as a whole; at the same time, it must ensure that we're not going to miss some of the potential and/or threaten already established system features by not understanding the intrinsic "rules".

Deliverables

The deliverables of the JWG were set out in the Terms of Reference for C1.29. The JWG aims to deliver the following:

1. A description of a possible scenario(s) including huge RES growth and increased level of control over DER

2. An overview of most common practices for HV steady-state network planning

3. An overview of potential adequacy of most common planning practices within the predefined scenario(s) and analysis of major gaps in terms of algorithms and datasets.

4. A description of the most promising innovative methodologies for HV steady-state planning, as resulting from papers presented at international conferences.

5. An overview of potential adequacy of innovative planning methodologies within the same predefined scenario(s).

6. A recommendation on steady-state planning methodologies for HV networks hosting significant DER. In terms of algorithms and datasets to be used.

Publish all findings in a brochure about "future-proof" demand planning criteria for Future Transmission Networks with an Executive Summary in Electra.

FUTURE ENERGY SCENARIOS WITH RENEWABLE ENERGY SOURCES (RES)

This section contains deliverable 1 of the TB: "A description of a possible scenario(s) including huge RES growth and increased level of control over DER".

Extreme Future Energy Scenario

Under 'Common Practices for Classical HV Stead-State Network Planning' the TB introduced, in generic terms, the most common planning "philosophies" which, in slightly different ways, are adopted to perform steady-state HV network planning. The TB also pointed at the fact that these methodologies were developed within the context of an electrical system in which all individual behaviours of distribution network users run unrestricted and their collective results could be forecasted according to combination rules (deterministic or probabilistic) and growth rates.

To give an example, in such a context it could be assumed that the "natural" evolution for the peak consumption of a given area where:

- a positive growth rate of installed power is foreseen for "passive" customer,

- no distributed generation exist,

is that power flow from HV to LV will increase.

What really threatens all these approaches is the introduction of the concept of active management of the available resources at MV and LV level: it implies that DSOs, by influencing the previously unrestricted behaviours of connected users, as well as by operating their own flexibility resources, are able to manage their systems in an unprecedented, and more efficient manner, optimizing operation, minimizing losses and limiting power exchange between HV and MV systems.

If we assume that in the future, for any given MV busbar, the embedded generation will be able to provide all the energy the loads require and that the load profiles of energy consumption and injection will be equalized through demand response activities and storage facilities, it can be easily seen that, the higher the level of control that DSOs can operate, the lesser the degree of HV loading that can be achieved.

A control strategy of this kind has - no doubt - a positive effect on the HV network, reducing the need for its reinforcement (at least due to limitations resulting from steady-state conditions), but at the same time reduces the degree of predictability of future "collective" behaviours, potentially making the HV planner "blind" over what's going on at lower voltage levels.

Under these conditions, in fact, the power exchange that can be measured at a given boundary point between MV and HV network does not only result from the "free combination" of network users behaviour, but also from the actions taken by the DSO; the same applies to combination rules that can be introduced to elaborate an aggregate consumption from individual users' data.

In a future scenario, where the power exchange between HV and MV is largely determined by actions carried out by the DSO (management of distributed generation and interconnection), the sizing of the HV network could be increasingly inefficient if historical demand data is used. This could result in under-sizing or over-sizing of the HV network, neglecting some critical conditions such as a DSO fault where control of distributed generation is lost. This TB focuses on actions required by the DSO & TSO but acknowledges that active network management starts with the originator of the generation. For house by house control of PV panels and data exchange with the DSO at this level also plays a large part.

To describe the most extreme condition, if a DSO would ensure at every given time the perfect balancing of active and reactive flows at MV level in any MV busbar, no load or generation would ever exist to be used in load flow calculations.

In this case, it is quite obvious that most common planning approaches in terms of input data will lead either:

- to a dramatic under-sizing of the HV network, in case the use of a series of historical data - which will have to be systematically kept close to zero - is maintained,

or

- to a substantial oversizing of the same network, in the case where dimensional data of components are adopted. Furthermore, in this case the degree of oversizing will be increased by the fact that actual needs are reduced, compared to present day situation, by the balancing actions performed by DSOs on MV system.

In order to cope with the above described future scenario, different planning approaches are then needed, based on more comprehensive elaborations on network users' data as well as on energy flows on HV/MV transformers. Also, contingency definition should be deepened (taking into account the probability of a loss of control over embedded resources, as an example).

COMMON PRACTICES FOR CLASSICAL HV STEADY-STATE NETWORK PLANNING

This section contains deliverable 2 in this TB is: "An overview of most common practices for HV steady-state network planning".

The objective of HV system planning is to determine a resilient, cost-effective and environmentally acceptable expansion plan for a reliable network operation in the future. The planning process can be described as a multi-objective optimization constrained by different constraints (technical, economical etc.) and objectives are determined by different variables.

Changes in the generation structure are important variables and can significantly affect HV system planning. The increase of DER in some regions has increased the intermittency of generation which is frequently located in the rural distribution systems as dispersed generation sources. Therefore, this embedded generation may cause a reverse power flow which may lead to a smaller power exchange between the transmission and distribution network.

The objective of this chapter is to present a review of state-of-the-art HV system planning data exchange (Questionnaire 1) and the transmission planning process applied by Transmission Operators/System Operators (TO/SOs) (Questionnaire 2). The questionnaires are analysed and summarised below.

Questionnaire 1 – Transmission Planning Data Exchange Questionnaire

Purpose of the questionnaire

Recently, transmission network planning has been strongly influenced by the volume of new RES being connected or planned to be connected to the power networks at all voltage levels. This means that more planning data may need to be exchanged between TSOs and DSOs because intermittent DER connection brings more uncertainty to transmission network planning.

The purpose of this questionnaire is to collect information about the type of data that is currently exchanged between TSOs and DSOs with specific regard to their interfaces in order to support transmission network planning.

Respondents of the Questionnaire

Questionnaires were sent out to the JWG C1.29 members and responses were received from 25 TSOs and DSOs. Those that answered the questionnaires can be seen below in **Erreur ! Source du renvoi introuvable.**. The responses represent five continents and include both developed and developing countries. It is therefore assumed that these variable demographics will aid to draw valuable conclusions of the way system planning is carried out in different countries.

Table 1: Respondents of Questionnaire No.1

No.	Company	DSO/TSO	Counties
1	Alliander	DSO	Netherland
2	Austrian Power Grid AG	DSO	Austria
3	Axpo Power AG	DSO	Switzerland
4	CNTEE Transelectrica SA	TSO	Romania
5	Elia	TSO	Belgium
6	Endesa Distribución	DSO	Spain
7	Enel Distribuzione S.p.a.	DSO	Italy
8	Enexis	DSO	Netherland
9	ERDF	DSO	France
10	Hydro One Networks Inc.	TSO and DSO	Canada

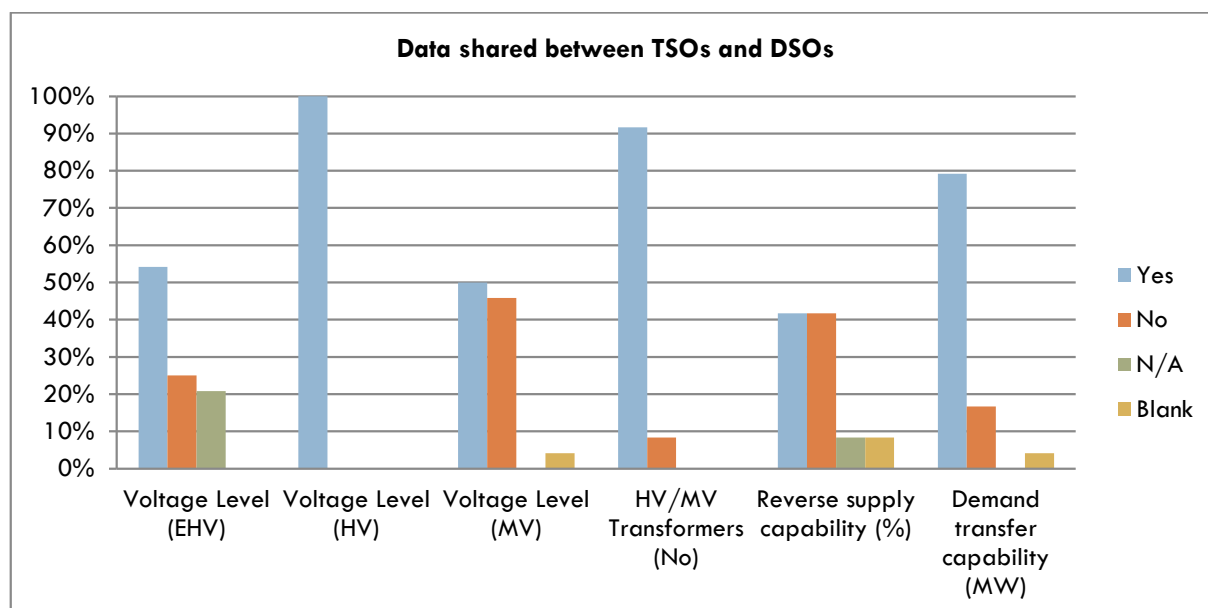| 11	Independent System Operator in Bosnia and Herzegovina	TSO	Bosnia and Herzegovina
12	National Grid	TSO	United Kingdom
13	ONS - Brazilian ISO	TSO	Brazil
14	Powerlink Queensland	TSO	Australia
15	Red Electrica de España	TSO	Spain
17	Rede Eléctrica Nacional (REN)	TSO	Portugal
18	RTE	TSO	France
19	State Grid Corporation of China	TSO and DSO	China
20	Svenska kraftnat	TSO	Sweden
21	TenneT TSO B.V.	TSO	German
22	The Kansai Electric Power Company	TSO and DSO	Japan
23	Transpower NZ	TSO	New Zealand
24	Vattenfall	TSO	Sweden
25	Vattenfall Eldistribution AB	DSO	Sweden

Summary

A very important step in the transmission network planning process is to obtain enough data to develop different scenarios with various uncertainties. Currently, the relevant parties only exchange some essential data (transformer data, historic and forecast generation and demand data etc.) to develop limited scenarios in the transmission network planning process. This is effective in traditional system planning because there is little uncertainty in the generation and demand requirements.

With more and more RES being connected to the distribution networks, there is greater uncertainty caused by intermittent energy supply. System planning becomes more challenging and it becomes difficult to build enough scenarios to find the balance point between security and economy without further information from stakeholders. Although some parties have realised this and asked their counterparts to provide more data, either through ad hoc requests or according to their regulatory instruments, this is still not widely used by all the TSOs and DSOs. More information should be exchanged through a standard method to improve system planning work in the future.

Detailed analysis of the questionnaire

SYSTEM PHYSICAL DATA

The system physical data is arguably the most important data for a system designer to build the study model and to carry out system studies due to the fact that HV substations are the interface of TSOs and DSOs. All parties exchange HV planning data with their counterparts as shown in Figure 1 and about half of them even exchange the Extra High Voltage (EHV) and MV data because they want to model the networks accurately.
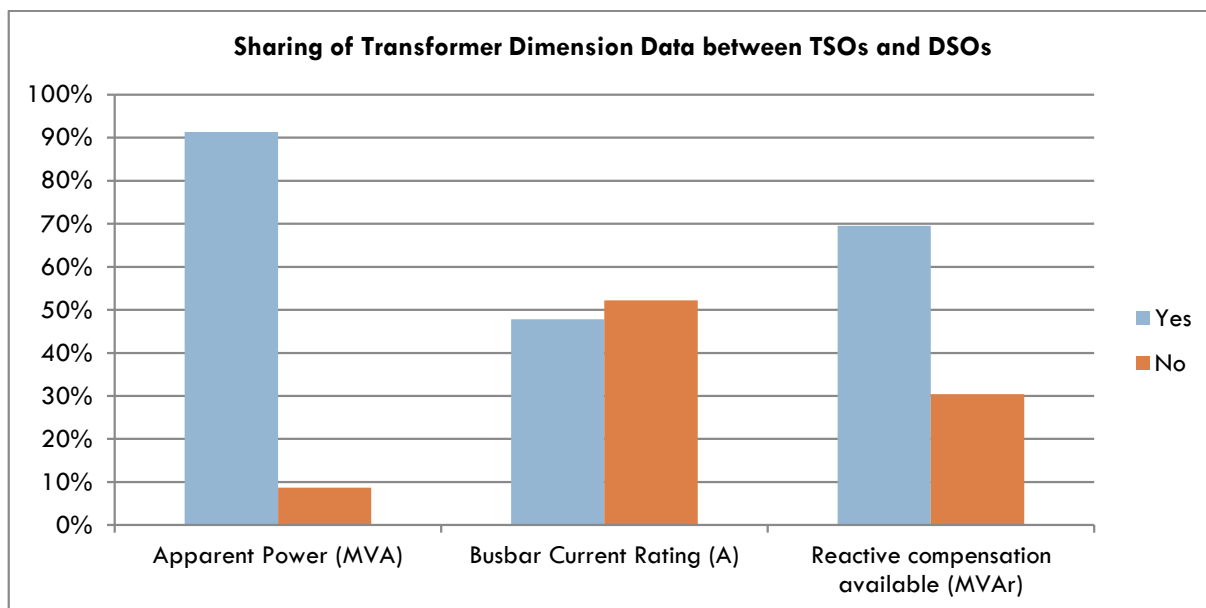
Figure 1: System Physical Data

As HV/MV transformers provide a link between transmission and distribution networks, they must have enough capacity to ensure that demand is safely supplied. HV/ MV transformer numbers are essential planning data because most TSO/DSO system planning criteria concentrate around N-1. The system planner should obtain this information to consider the unplanned or planned outage to secure the supply and demand when they do the system planning. About 92% of SOs exchange this information. To ensure security of supply and efficient network investment, demand transfer data is widely used in transmission planning, about 80% of the DSO and TSO exchange this information.

Although reverse power flows may become a significant in some rural areas with more embedded generator connections, in some extreme scenarios less than 50% of parties exchange the transformer reverse power flow capability information with their counterparts. There is a risk that due to owner/operator's lack of information, some contingency studies won't be carried out during network planning which will affect the investment decision process.

Renewable energy is highly unpredictable and with more and more renewables being connected to the distribution networks, there is growing uncertainty in transmission network planning. The system planner should plan the transmission network to be more cost efficient. More information on reverse power capability and demand transfer capability could be exchanged for future system planning with high renewable energy penetration. This will be discussed later in chapter 4.
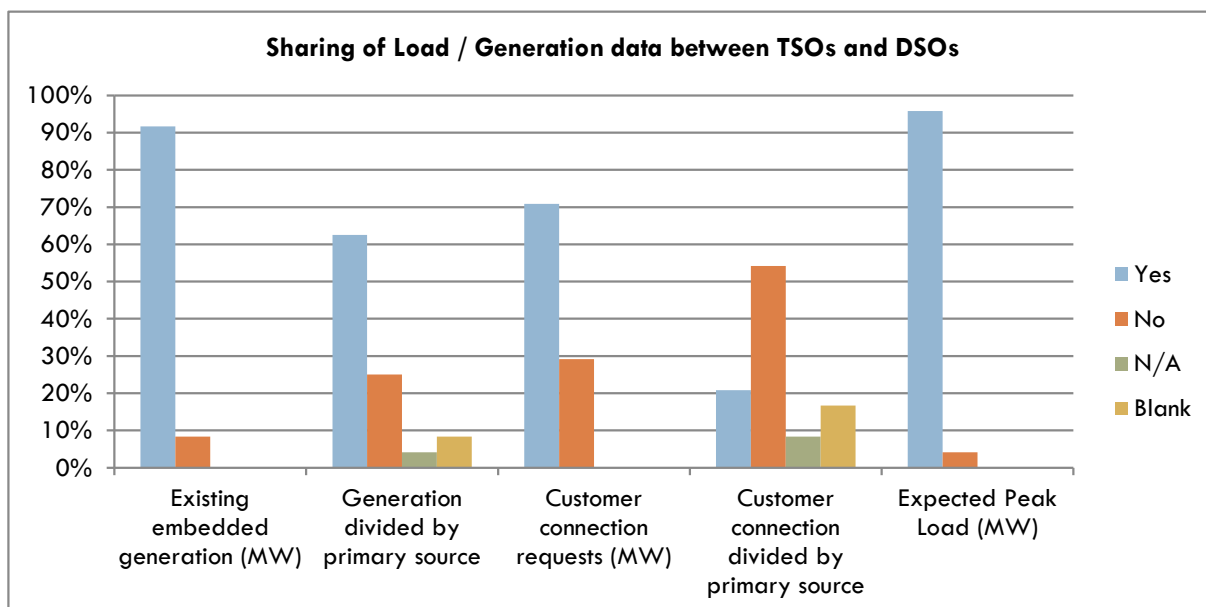
HV/MV TRANSFORMERS DIMENSIONAL DATA

Figure 2: HV/MV Transformers Dimensional Data

92% of SOs exchange transformer apparent power as transformer capacity is extremely important. Reactive Power capability is only shared between 70% of the parties (although the voltage issue is a big challenge under some extreme scenarios with new renewable connections) and only 50% of SOs exchange the busbar current rating with their counterparts.

LOAD/GENERATION DATA

Figure 3: Load/Generation Data

Another very important set of data is existing embedded generation and load data in the DSO networks. The system planning engineer should design enough network transfer capacity to secure the power supply but shouldn't waste many resources on the network redundancy. 92% of the parties exchange the existing embedded generation capacity.

The data provided for the embedded generator fuel type, is also very important. It determines the embedded generation's annual contribution in the DSO networks, which is an important input parameter to work out how generators feed the local demand. Only about 60% of DSOs' provide the existing generation fuel type to TSO.

For customer connection requests, only 70% of all DSOs provide the connection capacity to TSO. Even worse, only 21% of DSOs exchange the customer connection with generator fuel type. This may be a potential risk as the TSO system planner can't work out the embedded generator annual contribution which may cause either excess investment or insufficient investment to guarantee safe demand supply.

HISTORICAL DATA

To make any investment more efficient, the system planner should make decisions by collecting historical data to assess if their design meets the security and economic criteria required. The most important data that should be exchanged is the yearly maximal active and reactive power, because this determines the transmission networks capacity to secure the demand power supply. Only one party didn't exchange maximal active power information with their counterparts. The minimal demand is also very important to assess reverse power flow and high voltage issues, but only about 70% of parties exchange this information with counterparts.
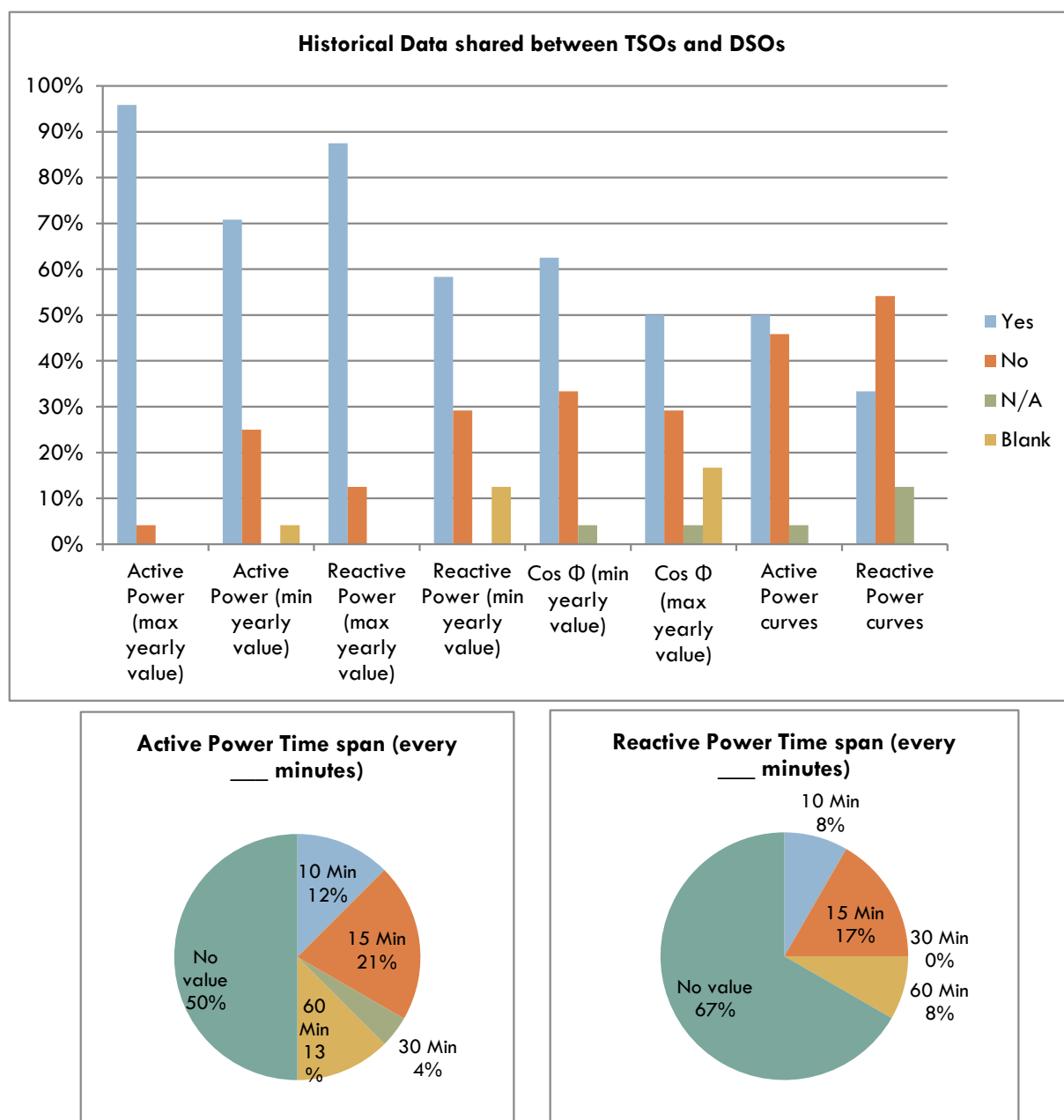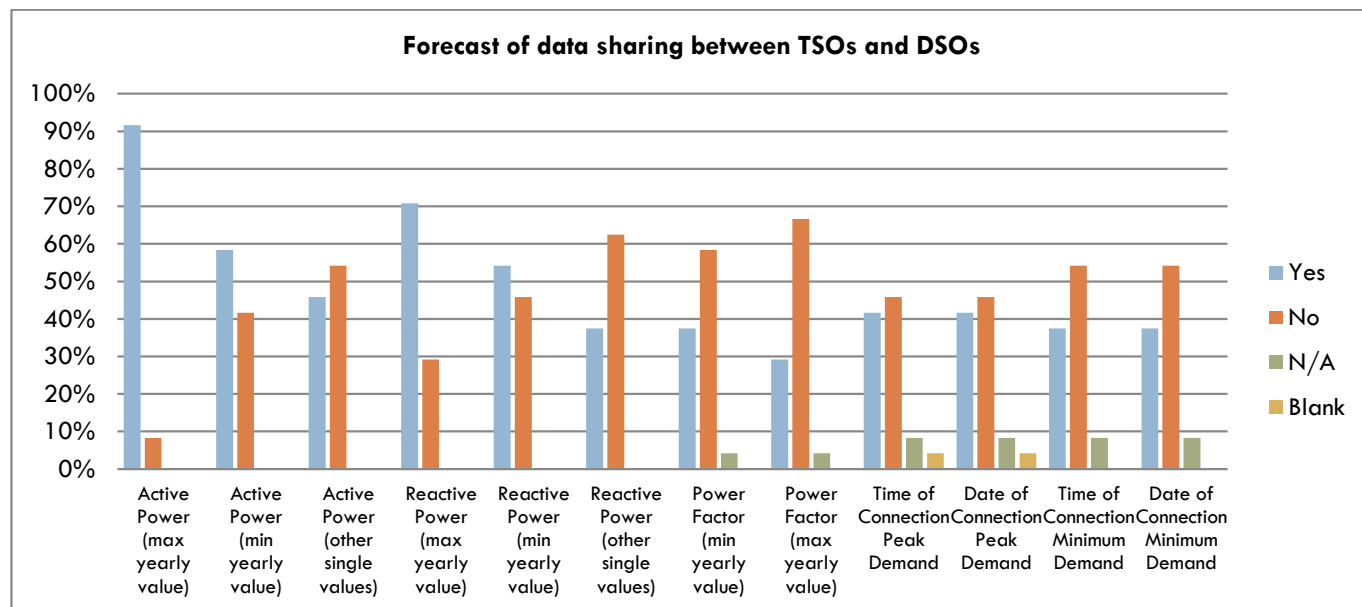

Figure 4: Historical Data

Only about 50% of parties exchange their Cos Φ and power curve data with their counterparts. There is no standard power curve time span as shown in Figure 4 although the 15 minute active and reactive power curve is widely used.

FORECAST DATA

Figure 5: Forecast data

To secure the power supply in the DSO network of the future, the forecast data should be used in system planning. 92% of parties exchange the maximum active power to ensure network safety. 70% of them also exchange the maximal reactive power. More than 50% exchange the minimal active power and reactive power which is very important for high voltage studies.

Only exchanging the maximal and minimal power is not enough as some parties may have extreme seasonal scenarios or operational constraint scenarios. For example, in the maintenance period or seasonal scenarios, some SOs may have seasonal generation or demand patterns where the maximal power flow or maximal reverse power flow will happen. To ensure system planning is more efficient and accurate, additional data needs to be exchanged other than just single values.

There is also no standard for whether to exchange maximal and minimal power factor across several years.

ANY OTHER DATA EXCHANGED

There is no standard for additional data exchanged among different parties. The majority of responsants have an agreement with their counterparties to request more information. Maintenance period or seasonal scenarios data is exchanged by some parties, and some may exchange data on an ad hoc basis, if they think more scenarios should be studied in specific network planning projects.

Questionnaire 2 – Transmission System Planning Questionnaire

Purpose of the questionnaire

The purpose of the "Transmission System Planning Questionnaire" was to better understand the transmission planning process applied by TSOs worldwide. The first section of questions asked about their optimization framework to reveal the objectives they pursue and the different restrictions they consider. The second section was dedicated to monitoring and control of DER. The goal was to determine what information and control capabilities TSOs might need to embed into their future planning processes in the wake of large growth in DER. The last section concentrated on gathering additional information such as planning cycles, number of scenarios, number of use cases, time horizon for planning and system modelling.

Respondents of the Questionnaire

The questionnaire was answered by eight TSOs from three different continents: Australia, South America and Europe. Table 1 shows all responses received to questionnaire 2. It is important to note that due to this small number of responses received the conclusions drawn in this report could be biased. If general conclusions were to be drawn, a larger number of responses would be required.

Table 1: Respondents of the Transmission System Planning Questionnaire

No.	Company	Country
1	National Grid	United Kingdom
2	Operador Nacional do Sistema Elétrico[1]	Brazil
3	Powerlink	Australia
4	Red Eléctrica de Espana	Spain
5	Réseau de transport d'électricité	France
6	SvenskaKraftnet[2]	Sweden
7	TenneT	The Netherlands
8	Transpower	Australia

OPTIMIZATION FRAMEWORK

RES have a growing impact on transmission system planning. Many uncertainties make it a highly sophisticated task to estimate a power systems' future as a basis for transmission system planning.

- Reliability of supply is hard to monetise correctly. Hence, all TSOs account for a certain reliability level by restricting their objective functions. Re-dispatch and curtailment cost are easier to determine and are hence frequently included in the optimization. Thus they are not seen as a restriction.

- The most crucial technical constraints are stability constraints, equipment loading constraints and equipment voltage tolerances.

- The interruption duration (in h) and the interruption of supply (in MW) are the most important indexes to quantify the reliability of the system. Customer numbers lost also make up a significant measure.

- More than half of the respondents perform contingency analysis with two network components failing simultaneously.

- Intertripping of volatile generators is an operational action that is considered during network planning by some TSOs.

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[1]With support from ONS

[2]We received two questionnaires from Sweden. They were answered by different individuals, one is from a TSO and another is from a DSO. In this section only the questionnaire of Mr. Petter Glantz (TSO) is analysed.

MONITORING AND CONTROLLING OF DER

- TSOs are generally not able to accurately forecast the output from RES generation themselves.

- They receive their forecast of RES generation primarily from external sources such as Balance Responsible Parties.

- More than 60 % of all respondents have online data about the availability of the RES generation.

- About 75 % of all respondents are able to curtail RES if necessary.

- Most TSOs have to instruct the DSO to curtail renewable generation.

- There is no common agreement as to who has to pay the curtailment cost as each country has its own regularities.
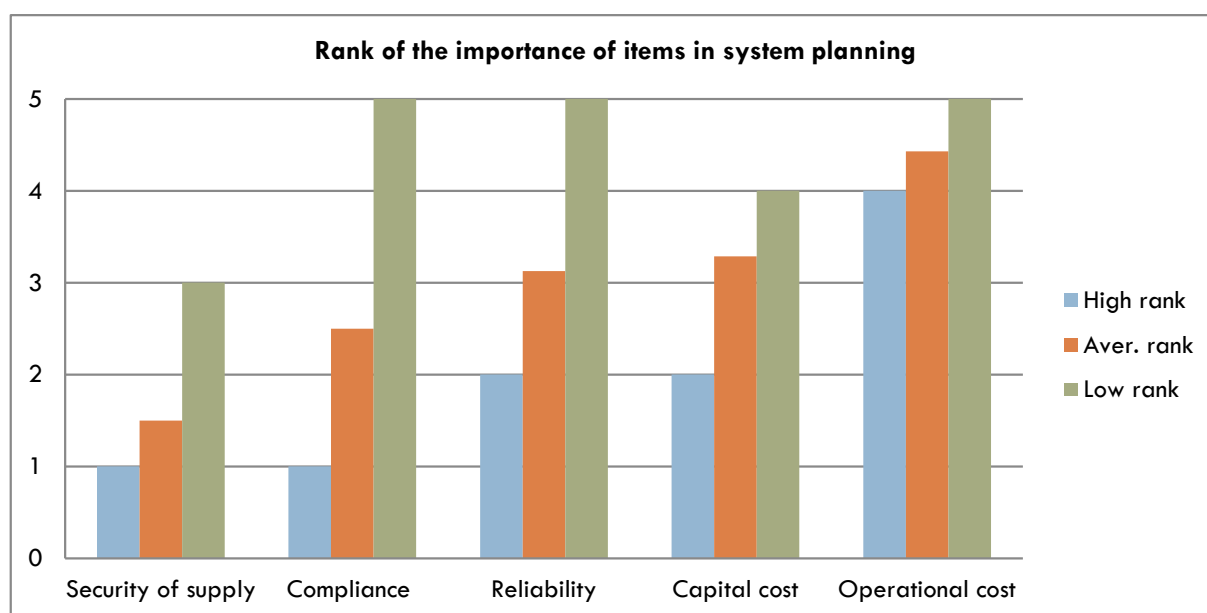
OTHER ASPECTS

- Official documentation relating to transmission systems planned with defined planning criteria is found in the grid codes.

- Three potential scenarios are identified in the Grid Code, but the actual number of scenarios being analysed largely depends on the degree of uncertainty in some TSOs.

- TSOs plan their systems in general for more than nine years ahead.

- Planning is dominated by an in-depth-analysis of some selected extreme cases. Operators may select those based on power flow studies of hourly planning cases.

- Networks are commonly modelled with shunt susceptance, series reactance and series resistance.

Detailed analysis of the questionnaire

OPTIMIZATION FRAMEWORK

Please rank the following items in order of performance related to planning of the transmission system. (Each item is given a score from 1 – 5 with 1 being the most important and 5 the least important)
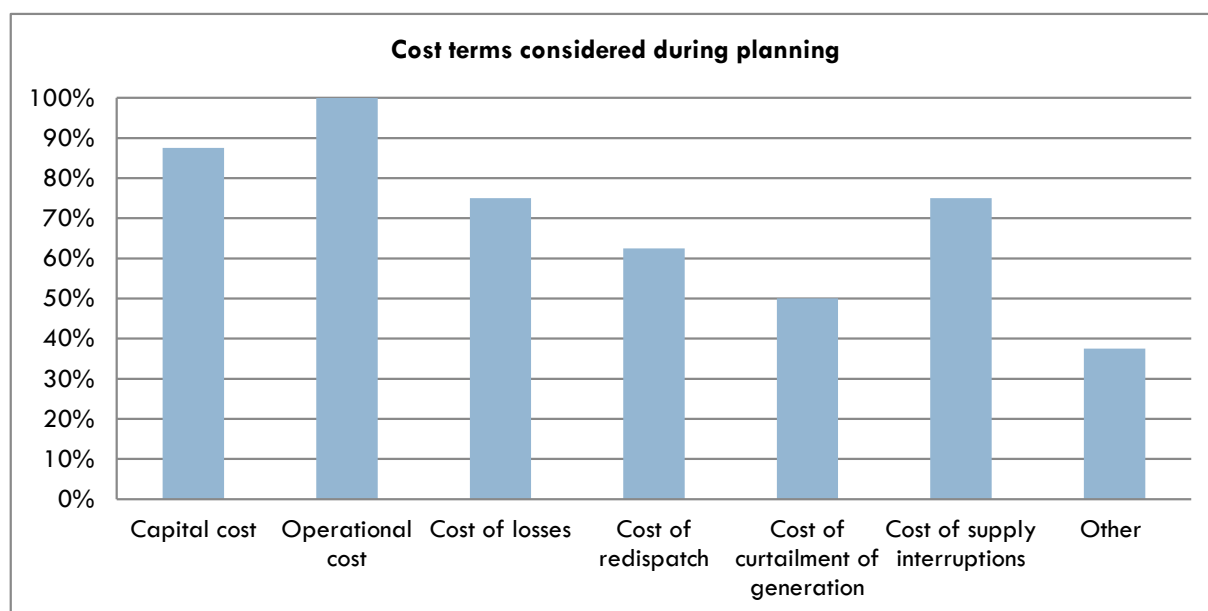

Figure 6: Importance of Items related to planning

The orange bars in Figure 6 show the average rank each item was assigned with. The blue and green bars additionally indicate the high rank and low rank that was assigned to each item.

The supply security, which means that TSOs must take into consideration that there is sufficient generation and transmission capability in the relevant area, to enable proper balancing of the load and generation, should take top priority. The second most important item is the compliance against technical standards, which is the basis for a reliable network operation. However, here there are high deviations in the ranking. RTE (France) ranks it least important while it has top priority with National Grid (United Kingdom) and SvenskaKraftnet (Sweden). The supply reliability is ranked third, followed by the capital cost and the operational cost of additional network assets. At Operator Nacional do Sistema Elétrico (Brazil) the capital cost are of least importance because the TSO is not in charge of system long term planning. In Brazil, conceiving and evaluating planning alternatives costs is a responsibility of Empresa de Pesquisa Energética (EPE) – an independent public company linked to the Ministry of Mines and Energy in Brazil.

The ranking indicates that a good transmission service is more important than the cost associated with its provision.

What cost terms do you consider in your objective function when planning the transmission system?

Figure 7: Cost terms of the objective function for system planning
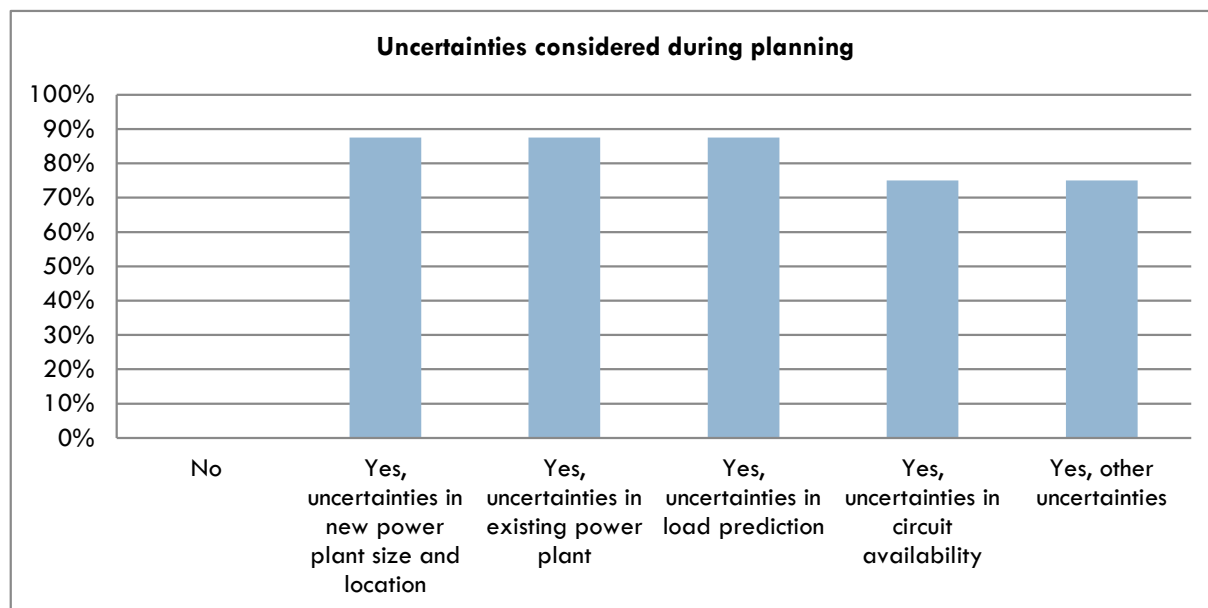
Figure 7 shows (in %) which cost terms TSOs mostly consider in their objective function during planning. These cost terms may include capital cost of investments and additional operational costs such as the cost of losses, the cost of supply interruptions, the cost of re-dispatch or the cost of curtailment of renewable energy sources.

Apart from the Brazilian TSO Operador Nacional do Sistema Elétrico, who is not in charge for the long term planning of its system (conceiving and evaluating planning alternatives costs is a responsibility of EPE – Empresa de Pesquisa Energética), all TSOs consider the capital cost of investments and cost of network losses. Five out of seven respondents (71.4%) at least include all cost terms in their objective function.

In addition to these cost terms, the Australian TSO Powerlink also includes the cost of voluntary load curtailment. The Swedish TSO SvenskaKraftnet also monetizes the public welfare. The only cost term considered by Operador Nacional do Sistema Elétrico are the cost of supply interruptions.

The fact that more than half of the respondents consider all of the cost terms in their objective function emphasizes the growing importance security of supply is to the consumer.

Which uncertainties do you take into account during transmission system planning?
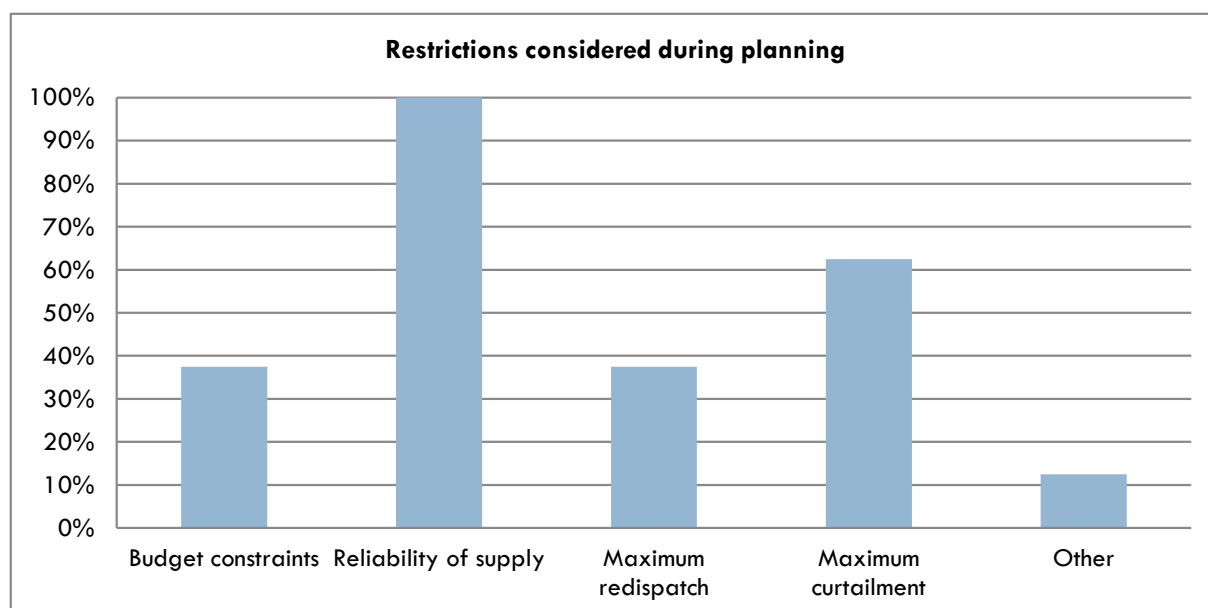

Figure 8: Uncertainties covered by TSOs during planning

Figure 8 shows some major uncertainties the TSOs have to take into account during their planning studies. The biggest uncertainty is in the location and size of new power plants, followed by existing power plants' future availability and the load prediction and last but not least the circuit availability.

The fact that at least 75% of all respondents consider all the mentioned uncertainties, along with additional provided comments, underline the complexity in estimating future conditions as a basis for transmission system planning.

In addition to the above pre-defined uncertainties, certain TSOs also take into account other uncertainties such as location and penetration of new RES (Red Eléctrica de España – Spain), delays in construction of power plants/transmission and distribution lines and equipment (Operador Nacional de Sistema Elétrico – Brazil) and uncertainties in network topology due to overhead lines and cable projects (SvenskaKraftnet - Sweden).

What kind of restrictions do you consider in your objective function when planning the transmission system?
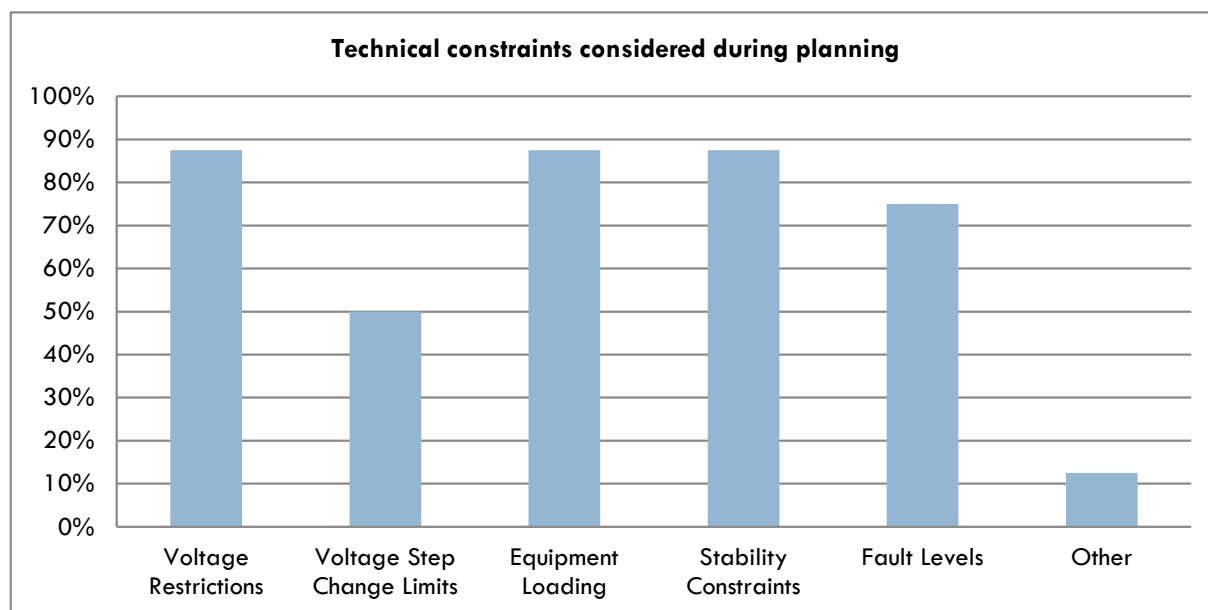

Figure 9: Restrictions considered during planning

Figure 9 shows the restrictions that the TSOs consider in their objective function when planning the transmission system. All the TSOs take into account the reliability of supply. Five out of eight also consider a maximum amount of curtailment of renewable generation. Only three out of eight consider a maximum amount of re-despatch or budget constraints. In addition, Réseau de transport d'électricité (France) also restricts the amount of maximum supply interruptions (in MW).

Reliability of supply is hard to monetize correctly, hence all TSOs account for a certain reliability level by restricting their objective function. Re-dispatch and curtailment cost are easier to determine and hence frequently included in the optimization. Thus they are not seen as a restriction.

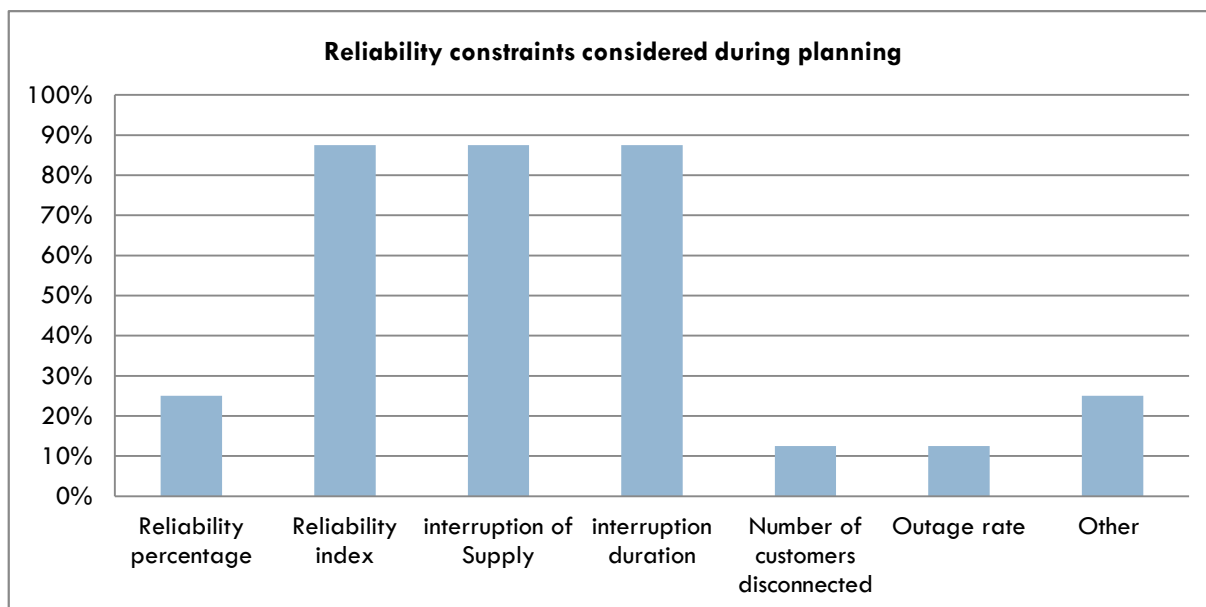### What technical constraints do you consider?

Figure 10: Technical constraints considered during planning

All TSOs take into account most of the technical constraints which are crucial in ensuring a reliable and secure network operation. With the exception of Réseau de transport d'électricité (France), all other TSOs consider minimum and maximum fault levels. Six out of eight TSOs apply Voltage Step change limits with France and Spain being the exceptions. In addition, Powerlink (Australia) and National Grid (UK) consider power quality issues such as unbalance and harmonics in the transmission planning process.

The most considered technical constraints are stability constraints, equipment loading constraints and equipment voltage tolerances.

What reliability constraints do you consider?

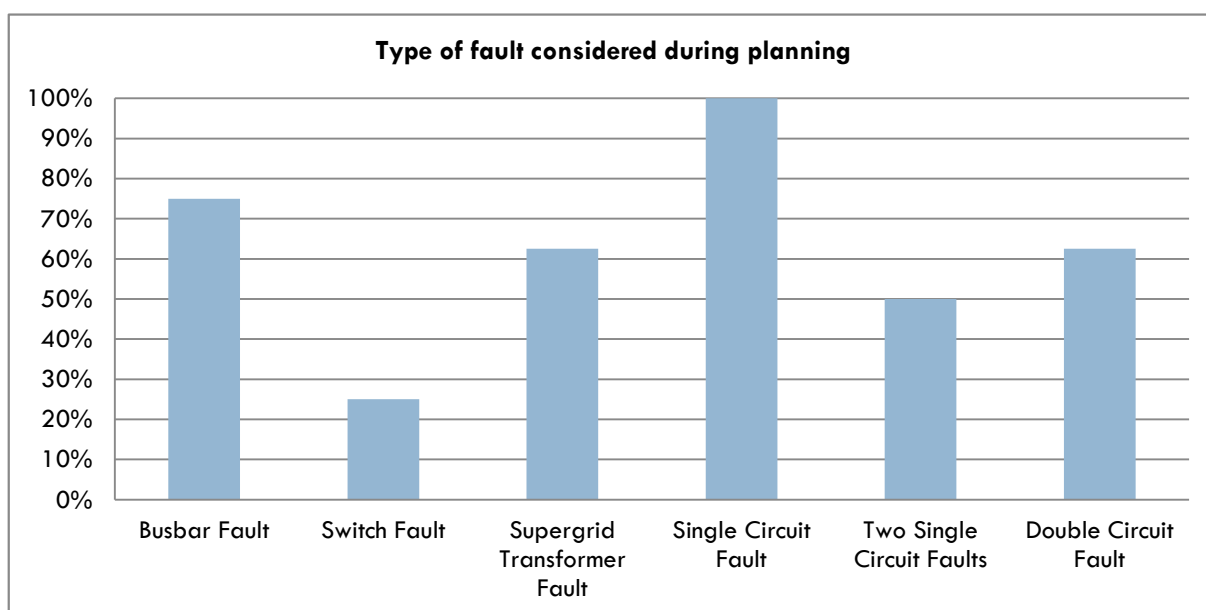**Reliability constraints considered during planning**

Figure 11: Reliability constraints during planning

Figure 11 displays the reliability restrictions used by TSOs when planning transmission systems. Seven out of eight TSOs use reliability indexes with 'interruption of supply (in MW)' and 'interruption duration (in hours)' are the most widely used methods with these TSOs. Operador Nacional do Sistema Elétrico in Brazil on the other hand exclusively relies on deterministic criteria such as (N-1) for the system as a whole and (N-2) for strategic installations to ensure a reliable network operation. The reliability percentage is restricted in Spain and in the Netherlands. TenneT – Netherlands also use customer numbers lost as a reliability constraint.

The interruption duration (in hours) and the interruption of supply (in MW) are the most important indexes to quantify the reliability of the system.

What type of faults do you consider?

Type of fault considered during planning

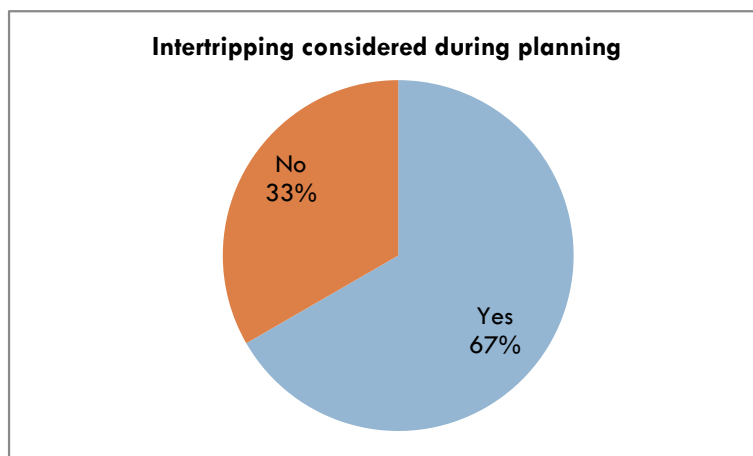**Figure 12: Considered faults in planning studies**

As Figure 12 shows, the TSOs consider a lot of different fault types in their contingency analysis. All of them must account for the single circuit fault in order to comply with the (N-1)-criterion. Busbar faults and double circuit faults usually have a low occurrence probability but a high impact on the system service. Hence, they are considered by

six out of eight and five out of eight respondents, respectively. A two circuit fault is considered by half of the respondents. In contrast to a double circuit fault, for a two circuit fault the failing circuits don't need to be on the same route, which introduces more failure combinations to be tested. A switch fault is only explicitly modelled by National Grid (United Kingdom) and the Spanish TSO Red Eléctrica de España.

More than half of the respondents perform contingency analysis with two network components failing simultaneously.

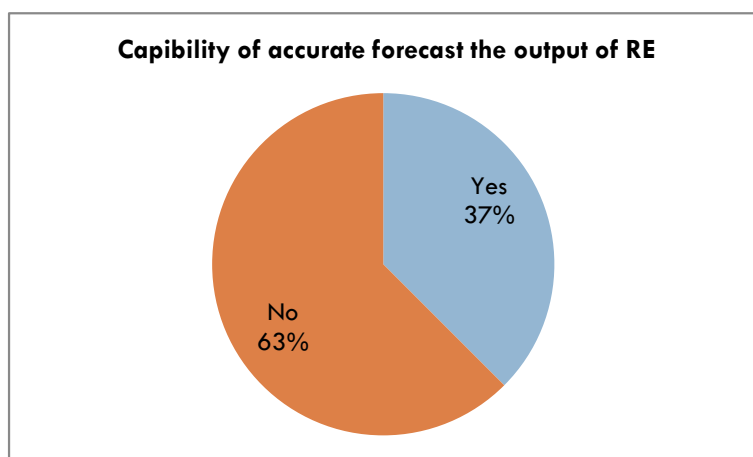**Do you use any form of intertripping as part of system planning?**

Figure 13: Intertripping considered during planning

This question was added post hoc to the original questionnaire and was only answered by three respondents. It is related to the intertripping of volatile generators. If their output might violate the operational limits of the network, the operator could disconnect them. As Figure 13 shows this ability is considered during system planning by two out of three respondents (SvenskaKraftnet and Operador Nacional do Sistema Elétrico). The Spanish operator Red Eléctrica de España has this ability too but does not consider it in its planning studies.

Intertripping of volatile generators is an operational action that is considered during network planning by some TSOs.

MONITORING AND CONTROLLING DISTRIBUTED ENERGY RESOURCES (DER)

Are you able to accurately forecast the output from Renewable Energy (RE) generation?

Figure 14: Ability to forecast RE-generation

Today, accurate RE generation forecasts are necessary to prepare daily network operation, especially for extreme weather situations. But as Figure 14 demonstrates only three out of eight respondents are able to perform accurate forecasts themselves. Those are Operador Nacional do Sistema Elétrico (Brazil), Red Eléctrica de España (Spain) and Réseau de transport d'électricité (France).

TSOs are generally not able to accurately forecast the output from RE generation themselves.

If no, is this forecast provided to you by the RE generator?

Forecast provide by RE generators

Yes
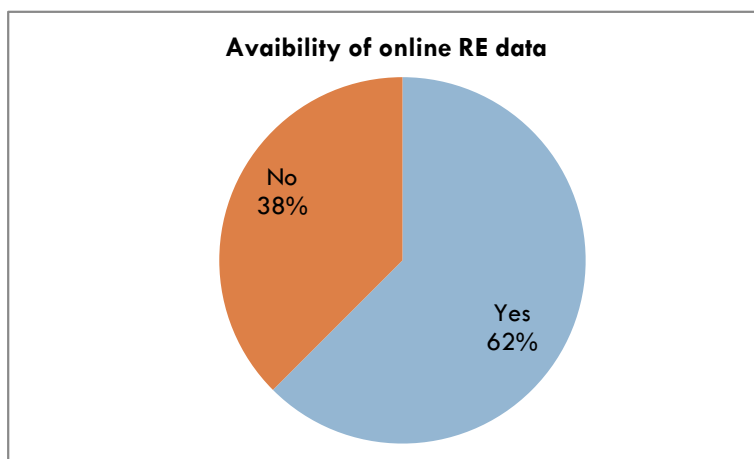12%

No
12%

Other
38%

No value
38%

Figure 15: Provider of RE generation forecasts

Figure 15 shows how many TSOs receive their forecasts from the RE-generators. In total, only five respondents answered this question. From these five, only Transpower (Australia) receives its' forecast directly from the RES generators. The other Australian TSO - Powerlink did not disclose its source. The two TSOs SvenskaKraftnet (Sweden) and TenneT (Netherlands) receive their forecasts from the Balance Responsible Party (BRP).

There is no common way for Transmission system operators to receive forecast of RE generation.

Do you have online data about RE generation available?

Avaibility of online RE data

No
38%

Yes
62%

Figure 16: Online availability of RE generation data

Figure 16 above shows that five out of eight respondents have online data about RE generation available in their control centres. Two TSOs, that don't have this data available online, despite high RES shares in their control area, are TenneT (Netherlands) and SvenskaKraftnet (Sweden).

More than 60 % of all respondents have online data about RE generation available.

Can you curtail RE, if necessary?

Capability of curtail RE

No
25%

Yes
75%

Figure 17: Option to curtail renewable generation

The ability to curtail renewable generation becomes more and more important to ensure power balance and a constant system frequency. Figure 17 shows that six out of eight respondents are able to curtail renewable generation if necessary. Only TenneT (Netherlands) and the Réseau de transport d'électricité (France) don't have the capability in imposing restrictions on RE generation..

About 75 % of all respondents are able to curtail renewable generation if necessary.

If yes, how do you curtail RE?

How to curtail RE
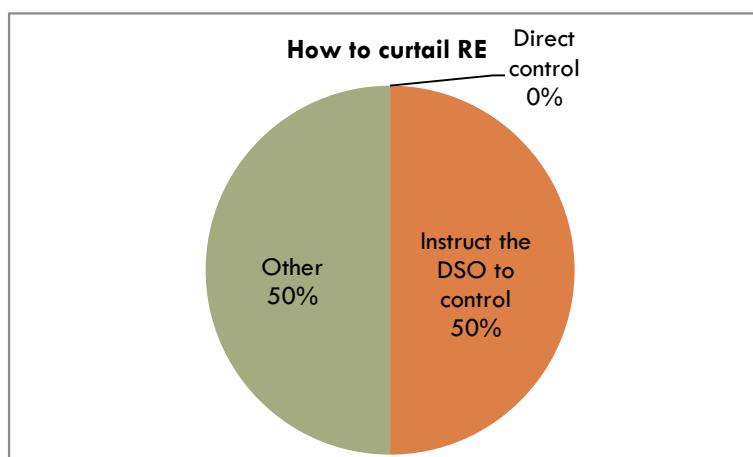
Direct control
0%

Instruct the DSO to control
50%

Other
50%

Figure 18: Options to curtail renewable generation

Figure 18 shows that four out of eight respondents instruct the DSO to curtail generation. In addition, SvenskaKraftnet has the direct control of the transformer breakers in substations at the TSO/DSO interface but uses them only in case of specific line faults. In Brazil, Operador Nacional do Sistema Elétrico directly instructs the owner or operator who controls the renewable generation unit (in its case wind farms) to cut off generation. No response received to this question from Résau de transport d'électricité and TenneT as they have no capability of curtailing RE generation. Although National Grid has the ability to curtail RE generation the method used is not yet defined.

It is evident that the majority of TSOs rely heavily on the DSOs to control RE generation in the DSO network to avoid adverse effects on the TSO networks.

Who will pay for the curtailment cost?

Figure 19: Authorities that pay the curtailed renewable generation

The responsible party for the curtailment cost largely depends on the regulatory regime of each country. In Australia, Spain and France it is the generation company that bears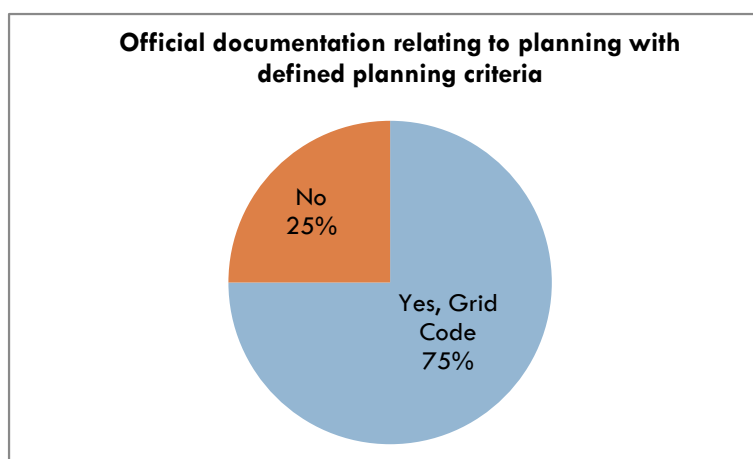 the cost. In Sweden the responsible party depends on the reason for the curtailment of RE generation, i.e. if the curtailment is due to a balancing action within the system then the BRP is responsible in paying the curtailment cost. In the Netherlands it is the TSO who is accountable for the curtailment cost. In Brazil and the UK it is not yet defined who is responsible for the curtailment cost which makes bilateral agreements a requirement. Figure 19 shows the distribution of all responses.

There is no common agreement as to who has to pay the curtailment cost, each country has its own regularities.

OTHER ASPECTS

Do you have official documentation relating to transmission system planned with defined planning criteria?

Figure 20: Documents relating to planning criteria

Figure 20 shows that the majority of the TSOs have a Grid Code that defines the transmission planning criteria within their transmission system. In addition to a Grid Code, National Grid in the UK also utilise a planning standards document. Sweden uses the Nordic Grid Code which is a common document between the TSOs in Nordic countries. Powerlink in Australia use a planning criteria document instead of a Grid Code.

Official documentation relating to transmission systems planned with defined planning criteria is found in the grid codes.

How many scenarios do you consider in your planning?
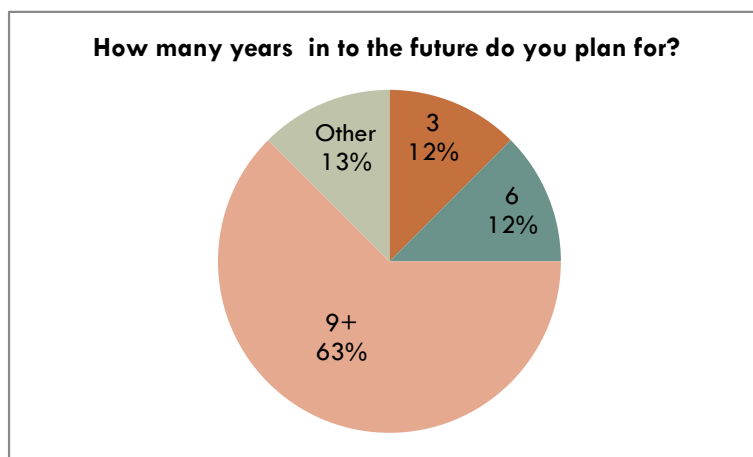
How many scenarios used for planning?

Figure 21: Number of scenarios during planning

Figure 21 shows that the respondents cover a number of scenarios, there is no exact number specified. Half of the responses declare that it depends on the subsystem individual characteristics. Operador Nacional do Sistema Elétrico (Brazil) didn't mention a specific number of scenarios but stated that it depends on the subsystem's individual characteristics. Powerlink (Australia) expressed that they will consider as many scenarios as needed depending on the uncertainty in the system. Réseau de transport d'électricité stated that they usually use 1-4 scenarios during system planning. SvenskaKraftnet showed the broadest range of possible scenarios, stating that their number usually differs between two and ten depending on case. However, they use two base cases (high load and low load case) which are tested in different scenarios. It is important to note that most of the TSOs consider more than three scenarios when planning their transmission system.

The actual number of scenarios largely depends on the degree of uncertainty.

How many years in to the future do you plan for?

How many years in to the future do you plan for?

Figure 22: Planning horizon

Figure 22 shows that the majority of TSOs plan their network more than nine years ahead. Operador Nacional do Sistema Elétrico (Brazil) only plans for three years ahead, because the Brazilian government agency (EPE) is in charge for the long term system planning up to 10 years ahead. Réseau de transport d'électricité (France) reports that it looks at scenarios up to 20 years ahead from now. Red Eléctrica de Espana (Spain) only plans the network up to 6 years in advance.

TSOs plan their systems in general for more than nine years ahead.

How do you analyse your planning cases during your planning?

Figure 23: Planning cases considered

Figure 23 shows the cases that are considered during planning. Basically there are two different options. The first one is to analyse all planning cases of a target year with power flow studies, for example in an hourly or even finer resolution, and the second is to focus on a selection of some system relevant extreme case such as extreme demand or weather variations. Those extreme cases are favoured by most of the respondents.

Red Eléctrica de España (Spain) states that it analyses all hourly planning cases with a DC power flow but takes a closer look at extreme cases using full AC power flow analysis. A similar approach is followed by TenneT (Netherlands). They also select some hourly planning cases based on extreme power flow results. National Grid (United Kingdom) reports that for high voltage studies, some special extreme cases will be studied, for example Summer bank holiday demand.

Transmission system planning is dominated by an in-depth-analysis of some selected extreme cases.

<u>**Which of the following parameters are used to represent the network?**</u>

Figure 24: Parameters to represent the network

Figure 24 shows how the TSOs represent their systems in their planning studies. They use general electrical parameters such as shunt susceptance, series reactance and series resistance. Only one TSO uses a PI-model with concentrated parameters and two TSOs also select thermal rating as a main parameter to represent their networks. Five out of eight TSOs also show the length of the branches to support the network.

The survey results indicate that it is common to represent the system with shunt susceptance, series reactance and series resistance.

Questionnaire 3 – DSO

Purpose of the questionnaire

HV network planning as performed by a DSO should not significantly differ from TSO planning for the same network, as far as the steady-state perspective is concerned. Nevertheless, it's worth noticing that planning practices and system priorities are slightly different from the ones highlighted by TSOs. This is probably due to the respective roles' overall priorities, which inevitably lead to giving different focuses to different issues.

Respondents of the Questionnaire

The questionnaire was answered by five European DSOs.

Table 3The questionnaire was answered by eight TSOs from three different continents: Australia, South America and Europe. Table 1 shows all responses received to questionnaire 2. It is important to note that due to this small number of responses received the conclusions drawn in this report could be biased. If general conclusions were to be drawn, a larger number of responses would be required.

Table 1: shows all responses that were analysed here. Note that, due to the small number of respondents, the conclusions drawn in this report just show some tendencies. If general conclusions are to be drawn, a larger number of respondents will be required.

Table 2: Respondents of the Distribution System Planning Questionnaire

No.	Company	Country
1	ERDF	France
2	ESBN	EIRE
3	RWE	Germany
4	Enel Distribuzione	Italy
5	Endesa Distribucion	Spain

The main findings coming from the answers to the three sections of the Questionnaire follow

OPTIMIZATION FRAMEWORK

As a general rule, DSOs are mainly focused on the service they need to provide to their end customers and let TSOs ensuring the overall system stability and reliability. According to that:

- Compliance to standards (voltage values, load limits, etc.) is generally the main issue, as it is considered as the main driver in detecting network criticalities in steady-state planning;

- Investment costs are highly considered in HV planning;

- Operational costs do not always rank the same, according to country Regulations and DSOs' investments evaluation rules

- Security of supply and reliability are differently interpreted in different DSOs, as in many cases these two issues are already incorporated in planning rules (e.g. acceptable technical solutions for solving network criticalities are defined *a priori* according to a reliability criterion, and so on).

When it comes to the cost elements that are considered as primary in investment planning, it is simply logical that cost of redispatch of DER is never considered, as until now DSOs are not allowed to perform these activities (unless for asset protection purposes).

Small differences appear when it comes to losses and operational costs, probably due to national/regional Regulations, while capital costs and cost of supply interruption are always considered.

In general, all DSOs show they take into account the economic aspects of their Regulations, in the sense that if incentives/penalties of any kind are foreseen in Regulation, they are also adopted as investment evaluation cost elements.

MONITORING AND CONTROLLING DER

The extent, and the way, in which DSOs can play their role highly varies in different utilities, and in different countries, mainly according to the existing regulations. It is reported that:

- Distribution system operators do not always perform forecasts about the output from RE generation.

- The smaller and more disperse the generation connected to the distribution network (e.g. as in Germany and Italy), the more the DSO is likely to perform forecasts by itself.

- Online data are generally available, but are mainly reported with reference to MV or "significant" generation plants.

- Curtailment is foreseen and performed according to national regulation.

- The DSO may receive instructions from the TSO to curtail renewable generation.

- Compensation for curtailment, if any, is allocated to the organisation who initially requested the curtailment.

OTHER ASPECTS

- Reference documentation is generally not public.

- The expected number of scenarios being analyzed is three, but the actual number largely depends on the degree of uncertainty.

- DSOs plan their HV systems in general for at least five years ahead.

- Planning is dominated by an in-depth-analysis of some selected extreme cases.

- Networks are commonly modelled with classical PI scheme including parallel susceptance, series reactance and series resistance.

CLASSICAL PLANNING PRACTICES SWOT/GAP ANALYSIS

This section contains deliverable 3 of this TB: "An overview of potential adequacy of most common planning practices within the predefined scenario(s) and analysis of major gaps in terms of algorithms and datasets."

SWOT Analysis

The key strengths, weaknesses, opportunities and threats to the current planning methodologies have been identified and are summarised in Table 3 below.

Table 3: SWOT Analysis

Strengths	Weaknesses

• Relatively simple base electrical model required with known variables . Processes are in place to ensure values remain known to those performing planning studies.
• Systematic/repeatable methodology used to identify extreme network cases and required contingencies
• Generally planners have known limits (examples being voltage and thermal loading of plant) that define the acceptability of results defined by documents such as the 'Grid Code'
• Based on established forecasting methodologies of user behaviour which has successfully been used to predict future behaviour
	• Reliant on accurate forecasting of:
	  o load growth and or reduction
	  o generation line ups
	    ▪ As a result, assumes no significant changes behaviour in the planning period
	• Existing agreements with DSOs and other network users requires a limit amount of information to be exchanged
	• Different SOs have different priorities altering the direction of the studies
	• There are a great number of uncertainties to be considered
	• Lack of visibility of DER actions

Opportunities	**Threats**

• The increased data requirement is widely accepted and the further requirements generally understood
  o Changes to the existing agreements could ensure that this data is made available
• The additional required data is known by a party and could be made available to the SO
• Process of determining load and generation values for load flow calculation essentially consists in defining a set of rules (e.g. in terms of contemporaneity coefficients, etc.) to add up all load and generations reference data which could be updated based on increased input data
• Most SOs have the ability to curtail RE which can limit the extremity of the possible conditions
	• Active management of the available resources at MV and LV level
	  o can influence the nature of the behaviour of the system use which may result in either under or over sizing of the network
	  o introduces new contingencies
	• The number of simulations to be run increases, as the worst possible cases result from a higher number of intersections between load and generation scenarios
	• Negligible power exchange between the transmission and distribution network during normal operation

GAP Analysis

The desired future state is for network planning to be in a position to guarantee a secure and affordable network allowing for greatly increased DER. Currently, details required to build up a suitably detailed electrical model are readily accessible and processes are in place to ensure that these details are communicated to the relevant parties. Traditional outages are understood and certain levels of required system performance are generally defined for the different conditions. Simple methods for extrapolating distribution system changes in interaction with the transmission system are used for long term planning.

To ensure that the future state can be achieved, a method for understanding the possible exchange in power between DSO and TSO needs to be developed which accounts for the increase in DER and the many new uncertainties that this introduces. This will require a greater exchange in information than that generally undertaken. The key parameters to be defined would be the volume, type and availability (including details of inter-tripping and local control) of DER. There is much greater uncertainty in the realisation of proposed DER developments and therefore a method of dealing with the varying potential levels of DER in the future needs to be considered.

INNOVATIVE METHODOLOGIES FOR HV STEADY-STATE NETWORK PLANNING

This section includes deliverable 4: "A description of the most promising innovative methodologies for HV steady-state planning, as resulting from papers presented at international conferences".

Literature Review

This literature review is split into two aspects. Firstly, it covers Transmission Planning Methodologies (TPM) from a number of TSOs that have been chosen based upon the representation as part of the JWG and the maturity level of their TPM documentation. Secondly, a literature review of relevant technical papers is presented taken from sources such as the Institute of Engineering Technology (IET) and the International Council on Large Electric Systems (CIGRÉ).

Transmission Planning by Selected TSOs

TPM reported in this section represent established planning techniques already applied in existing TSOs and can be seen as best practice in this respect.

It is interesting to highlight the fact that they are mainly focussed on contingencies that must be examined in order to identify the severest system conditions, and the actual values which cannot be exceeded to ensure acceptable operating conditions are met.

No specific mention is made to load/generation input data used for calculating the planning criteria, which could imply that minimal impact on the TSO/DSO interface is expected if this data were taken into account. Hence projected data at the interface remains 'conventional'.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (USA)

California Independent System Operator (CAISO) [1] planning standards follow the North American Electric Reliability Corporation (NERC) [2] reliability standards which are further specified by Western Electricity Coordinating Council (WECC) [3] Regional Criteria and the ISO's own standards. The TPM documentation used by CAISO specifies an N-X reliability criterion of the system under different conditions and ensures that the system planner has to have a documented corresponding assessment as well as corrective plans.

The different system conditions are categorized as follows:

- Category A: normal conditions (no contingency or "intact");

- Category B: conditions with loss of a single element (single contingency);

- Category C: conditions with loss of two or more (multiple) elements;

- Category D: conditions when extreme events occur, resulting in multiple elements removed or cascading out of service.

These categories are further specified based on their initiating events and contingency elements. For each of these specified categories, the desired system performances are defined by the following aspects:

- Thermal and voltage limits;

- Loss of demand or curtailed firm (contracted) transfers;

- Cascading outages

However, these parameters are not applicable for Category D. The desired system performances for Category D are based on further evaluation for risks and consequences by the planners.

Two examples are shown on below in

Table 5.

Table 5: Example of Planning Standards for CAISO

Category	Initiating Event(s)	Contingency Element(s)	Desired System Performance(s)		
			System stability and thermal/voltage limits with ratings	Loss of demand or curtailed generation	Cascading outages
A	All facilities in service		Yes	No	No
C	Single Line to Ground fault with normal clearing	A single section of busbar	Yes	Planned/Controlled	No

In addition, WECC Regional Criteria define additional standards for each NERC's categories with the following aspects:

- Maximum outage rate (outage/year);

- Maximum transient voltage dip standard;

- Minimum transient frequency standard;

- Maximum post transient voltage deviation.

Conditions which fall into Category B, for example, shows more than 0.33 outages per year. They must not exceed 25% of transient voltage dip, not fall below 59.6 Hz of frequency for 6 cycles, and not exceed 5% of post transient voltage deviation. However, these criteria are assumed to be applied in further planning stage and therefore are not further described.

The ISO's own standards specify values and additional criteria. The inequality constraints are the voltage limits on each NERC Category as mentioned in (1.1) to (1.4), maximum loss of supply as mentioned in (1.5), outage rate limits as mentioned in (1.6) to (1.8) and thermal loading limit on each NERC Category as mentioned in (1.9) to (1.11).

$$1\,p.u. \leq U^A_{i \geq 500\,kV} \leq 1.05\,p.u. \tag{1.1}$$

$$0.95 p.u. \leq U^A_{i < 500\,kV} \leq 1.05 p.u. \tag{1.2}$$

$$0.9 p.u. \leq U^B_i \leq 1.1\,p.u \tag{1.3}$$

$$0.9 p.u. \leq U^C_i \leq 1.1\,p.u \tag{1.4}$$

$$P^B_{SL} \leq 250\,MW \tag{1.5}$$

$$\lambda^B \geq 0.33\,1/a \tag{1.6}$$

$$0.33 \leq \lambda^C \leq 0.33\,1/a \tag{1.7}$$

$$\lambda^D < 0.33\,1/a \tag{1.8}$$

$$S^A_{ij} < S_n \tag{1.9}$$

$$S^B_{ij} < S_n \tag{1.10}$$

$$S^C_{ij} < S_n \tag{1.11}$$

Where:

A *NERC Category A*

B *NERC Category B*

C *NERC Category C*

U^A *Voltage magnitude at bus i on Category A*

U^C *Voltage at bus i on Category C*

P_{SL}^B *Active power supply losses under Category B*

λ^B *Outage rate on Category B $(\frac{1}{year})$*

λ^C *Outage rate on Category C $(\frac{1}{year})$*

λ^D *Outage rate on Category V $(\frac{1}{year})$*

S_{ij}^A *Apparent power on line ij on Category A*

S_{ij}^B *Apparent power on line ij on Category B*

S_{ij}^C *Apparent power on line ij on Category C*

S_n *Apparent power thermal rating*

Voltage limits on each NERC Category, except Category D, are described in (1.1) to (1.4). It is important to note that the minimum voltage limit applies only to load and generating busbars within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage. The maximum voltage limits apply to all busbars since unacceptable high voltage is harmful to power stations, distribution and transmission equipment.

NATIONAL GRID (UNITED KINGDOM)

National Grid is legally obliged in accordance with their Transmission License to design, maintain and operate their network economically and efficiently. In order to plan the network to cater for current and future generation and demand capacity National Grid use their planning standards, known as the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) [4].

In accordance with the NETS SQSS, the transmission system shall be planned such that, for specified background conditions, there shall not be any of the following:

1. Equipment loadings exceeding the pre/post-fault rating;

2. Voltages outside the pre/post-fault planning limits or insufficient voltage performance margins;

3. System instability under intact and fault conditions;

4. A loss of supply capacity except those that are permitted by the "demand connection criteria" detailed in Chapter 3 of the NETS SQSS.

Further to this the different system conditions that are covered by the NETS SQSS are as follows:

- Normal system conditions (i.e. no outage meaning the system remains "intact");

- A fault outage on a single transmission circuit or reactive source (N-1);

- A double circuit overhead line on the supergrid (N-D);

- A single transmission circuit with the prior outage of another transmission circuit (N-2 or N-1-1);

- A section of busbar or mesh corner (N-1); or

- A single transmission circuit with the prior outage of a generating unit or reactive source (N-2).

The system instability describes a condition where the system experiences poor damping or pole slipping of the synchronised generating units. Its assessment requires short circuit calculations, and therefore is not further described in the NETS SQSS.

The equipment loading is bounded by its thermal rating. The inequality constraints are the voltage limits as shown in (2.1) to (2.6), the equipment overloading limits in (2.7) and (2.8), and the loss supply capacity limit in (3.9).

$$0.975 \; p.u. \leq U_{i=400kV} \leq 1.025 \; p.u. \qquad \textbf{(2.1)}$$

$$0.95 p.u. \leq U_{i=275kV} \leq 1.05 p.u. \qquad \textbf{(2.2)}$$

$$U_{i<275kV} \leq 1.05 \; p.u. \qquad\qquad \textbf{(2.3)}$$

$$0.95 p.u. \leq U^f_{i=400kV} \leq 1.025 \; p.u \qquad\qquad \textbf{(2.4)}$$

$$0.9 p.u. \leq U^f_{i=275kV} \leq 1.05 \; p.u \qquad\qquad \textbf{(2.5)}$$

$$U^f_{i<275 \; kV} \leq 1.05 \; p.u \qquad\qquad \textbf{(2.6)}$$

$$S_{ij} < S_n \qquad\qquad \textbf{(2.7)}$$

$$S^f_{ij} < S^f_n \qquad\qquad \textbf{(2.8)}$$

$$P_{SC,min} \leq P^f_{SC,s} \qquad\qquad \textbf{(2.9)}$$

Where:

$U_{i=400kV}$	$Pre-fault\ voltage\ at\ bus\ i\ at\ 400\ kV$	S_{ij}	$Apparent\ power\ on\ line\ ij$
$U_{i=275kV}$	$Pre-fault\ voltage\ at\ bus\ i\ at\ 275\ kV$	S_n	$Pre-fault\ continuous\ thermal\ rating$
$U_{i<275kV}$	$Pre-fault\ voltage\ at\ bus\ i\ less\ than\ 275\ kV$	S^f_{ij}	$Apparent\ power\ on\ line\ ij\ post-fault$
$U^f_{i=400\ kV}$	$Post-fault\ voltage\ at\ bus\ i\ at\ 400\ kV$	S^f_n	$Post-fault\ continuous\ thermal\ rating$
$U^f_{i=275\ kV}$	$Post-fault\ voltage\ at\ bus\ i\ at\ 275\ kV$	$P_{SC,min}$	$Minimum\ supply\ capacity$
$U^f_{i<275\ kV}$	$Post-fault\ voltage\ at\ bus\ i\ less\ than\ 400\ kV$	$P^f_{SC,s}$	$Post-fault\ supply\ capacity\ at\ point\ s$

Voltage limits in normal operation (pre-fault) are shown in (2.1) to (2.3). They differ based on the voltage level. There are two additional notes concerning these limits. The first one is that on voltage level 400 kV; an upper limit of 1.05 p.u. is permissible for no longer than 15 minutes. The second one is that on voltage level less than 275 kV, there is no minimum planning voltage for a lower voltage supply provided that it is possible (for example by tap changing) to achieve up to 1.05 p.u. of rated voltage at the bus on the LV side.

The steady state voltage limits after fault(s) are shown in (2.4) to (2.6). The loading limits before and after fault(s) are shown in (2.7) and (2.8). The pre-fault thermal rating generally has a smaller value than the post fault rating. The ratings are listed in National Grid's rating tables, which cannot be accessed publicly. The post-fault limits of voltage and current must not be violated after the list of contingencies found above.

The loss of supply capacity is described as the reduction of the post-fault supply capacity $P^f_{SC,s}$ at points s, which is the point of supply from the transmission system and other network operators (such as DSOs) or customers.

The permissible loss of supply between TSOs and DSOs is defined in the NETS SQSS as the following:

Table 6: Minimum planning supply capacity following secured events

Group Demand	Initial system conditions	
	Intact system	**With single planned outage**
Over 1500 MW	**Immediately** Group Demand	**Immediately** Group Demand
Over 300 MW to 1500 MW	**Immediately** Group Demand	**Immediately** Maintenance Period Demand **Within time to restore planned outage** Group Demand
Over 60 MW to 300 MW	**Immediately** Maintenance Period Demand **Within time to restore planned outage** Group Demand	**Within 3 hours** Smaller of (Group Demand minus 100 MW) and one-third of Group Demand **Within time to restore planned outage** Group Demand
Over 12 MW to 60 MW	**Within 15 minutes** Smaller of (Group Demand minus 12 MW) and two-third of Group Demand **Within 3 hours** Group Demand	Nil
Over 1 MW to 12 MW	**Within 3 hours** Group Demand minus 1 MW **In repair time** Group Demand	Nil
Up to 1 MW	**In repair time** Group Demand	Nil

The $P_{SC,s}^f$ must be greater than the minimum supply capacity $P_{SC,min}$, as mentioned in (2.9). The minimum supply capacity depends on the supplied load size and the initial system conditions. For example, a 70 MW load with the initial intact system, has the minimum supply capacity of the load size minus 20 MW, immediately after fault.

Where network assets are insufficient to meet the security requirements, it is necessary to assess the contribution to security from large power stations connected at either the transmission connection interface or embedded within the Network Operator's system. This will identify whether the aggregate generation capacity of the large power station connected to the network has the potential to meet any deficit in System Security from network assets.

The combined contribution by Large (≥100 MW) power stations shall never have a greater impact on system security than the loss of the largest circuit infeed to the group. The contributions from local power stations provide additional capacity to enable the supply of demand which may not otherwise be met following a secured event, but shall not replace the requirement for system connection. The assessment of contribution of generation to group security will therefore consider;

- the generation annual load factor

- the availability of generation under outage conditions

- the fuel source availability, i.e. whether energy is continuous, stored, storable or predictable

- common-mode failure mechanisms such as common fuel source, connections or plant stability / ride-through capability

- capping of generation contribution in the event that the generation contribution is dominant with respect to circuit infeed capability.

In addition to this, National Grid assesses the security of demand connection capacity with neighbouring DNOs. This is done in collaboration with each responsible DNO. The demand which is applicable for the assessment of connection capacity requirements is dependent on the nature of the associated connections, where the network associated with a transmission connection comprises solely of demand connections, i.e.

- there are no power stations of any size, and

- the customer's generating plant associated with any composite-user site does not have the ability to exceed the associated on-site demand,

the Group Demand is equal to the Network Operator's estimated maximum demand for the group which they believe could reasonably be imposed on the onshore transmission system, after taking due cognisance of demand diversity.

For those distribution networks which play host to connections of Small (<50 MW) or Medium (50 MW to <100 MW) power stations (or composite user sites with export potential), the generation can result in differences between Operator's estimated maximum demand for the group, which they believe could reasonably be imposed on onshore transmission system after making an appropriate allowance for load diversity and any demand masked by the export from small and medium power stations which are not expected to have the same operating regime in the future

50HERTZ, AMPRION, TENNET TSO AND TRANSNET BW(GERMANY)

According to the planning principles stated by all of German TSOs [5], the inequality constraints are the operating voltage limit as mentioned in (3.1) to (3.2), thermal loading limit of line as mentioned in (3.3) and the compliance of N-1 criterion as mentioned in (3.4) to (3.9).

$$1 \, p.u. \leq U_{i=380kV} \leq 1.1 \, p.u. \tag{3.1}$$

$$0.95 p.u. \leq U_{i=220kV} \leq 1.1 p.u. \tag{3.2}$$

$$U_{ij} \leq \beta \cdot I_n \tag{3.3}$$

$$0.95 p.u. \leq U_{i=380kV}^f \leq 1.15 \, p.u \tag{3.4}$$

$$0.90 p.u. \leq U_{i=220kV}^f \leq 1.15 \, p.u \tag{3.5}$$

$$I_{ij}^f \leq 3600 \, A \tag{3.6}$$

$$I_{ij}^{f*} \leq 4000 \, A \tag{3.7}$$

$$S_{GenLoss}^f < 2000 \, MW \tag{3.8}$$

$$P_{GenLoss}^{f*} \leq 3000 \, MW \tag{3.9}$$

Where:

$U_{i=380kV}$ $Pre-fault \; voltage \; at \; bus \; i \; at \; 380 \; kV$

$U_{i=220kV}$ $Pre-fault \; voltage \; at \; bus \; i \; at \; 220 \; kV$

I_{ij} $Curent \; magnitude \; between \; bus \; ij$

$U_{i=220 \, kV}^f$ $Post-fault \; voltage \; at \; bus \; i \; at \; 220 \; kV$

I_{ij}^f $Post-fault \; current \; between \; bus \; ij$

I_{ij}^{f*} $Current \; magnitude \; in \; the \; case \; of \; bus \; bar, and \; common \; mode \; faults$

β	*Maximum thermal loading in percentage*	$P_{GenLoss}^{f}$	*Active power generation loss in the case of one busbar failure*
I_n	*Rated current*	$P_{GenLoss}^{f*}$	*Active power generation loss in failure of couple busbars of circuits*
$U_{i=380\ kV}^{f}$	*Post − fault voltage at bus i at 380 kV*		

According to the N-1 principle any single failure event must not endanger the network security. The system must maintain the following ranges the case of a failure: the voltage limit as mentioned in (3.4) to (3.5), the same thermal loading limit as in normal operation as mentioned in (3.3), the current limit for network protection as mentioned in (3.6) and (3.7) and the generation loss limit as mentioned in (3.8) and (3.9).

The current limit in (3.6) is applied to avoid recurrence of network protection after a fault clearing. However, a higher limit value is applied in the case of bus bar, common mode and independent multiple failure as mentioned in (3.7). In those cases, one or more network protection is necessary for fault clearing due to power swing.

TRANSGRID (AUSTRALIA)

The transmission planning criteria that TransGrid are obliged to satisfy is documented within the following set of standards:

- National Electricity Rules (NER) provided by the Australian Energy Market commission (AEMC) [6]

- New South Wales (NSW) government's Transmission Network Design and Reliability Standard [7]

- Additional criteria for the Australian Capital Territory (ACT) [8]

The NER specifies the minimum network performance requirements to be provided including contingency events to be considered, power transfer capabilities during single outage, voltage magnitude, and rating of equipment. Some of these aspects are only stated as general requirements which need to be specified in the NSW's Standard. There are more aspects such as voltage harmonics, voltage stability, and fault clearance times which are also specified in NER however, these are considered to be used in further planning process.

In addition, since TransGrid are also responsible to serve load in the Australian Capital Territory (including Canberra), additional criteria have to be considered. These criteria are specified year-by-year and updated periodically based on the performance requirements in ACT.

The inequality constraints are the pre- and post-fault voltage limit on the supply point as mentioned in (4.1) and (4.2), minimum post-fault supply capacity in (4.3) and thermal loading limits which are specified based on the equipment ratings like mentioned previously in (2.7) and (2.8). The criteria for forecasted demand with a certain Probability of Exceedance (POE) after fault(s) shown in (4.4) and (4.5) are only applied to NSW main transmission network.

$$0.9 p.u. \leq U_s \leq 1.1 p.u. \tag{4.1}$$

$$[1-\alpha]p.u. \leq U_s^f \leq [1+\alpha]p.u. \tag{4.2}$$

$$0.75\ P_{d,s,max} \leq P_{SC,s}^f \tag{4.3}$$

$$P_d(50\%\ POE) \leq P_{SD,max}^f(ADP) \tag{4.4}$$

$$P_d(10\%\ POE) \leq P_{SD,max}^f(LDP) \tag{4.5}$$

Where:

s	*Supply point*	$P_d(\ )$	*Forecasted demand with different probability of exceedance*

U_s	$Pre-fault\ voltage\ at\ s$	$P_{SC,max}^{f}(\ )$	$Post-fault\ max\ supportable\ demand$
U_s^f	$Post-fault\ voltage\ at\ s$	ADP	$All\ Dispatch\ Patterns$
α	$Percentage\ of\ voltage$	LDP	$Limited\ Dispatch\ Patterns$
$P_{SC,s}^{f}$	$Post-fault\ supply\ capacity\ at\ s$	$P_{SC,s,max}^{f}$	$Maximum\ supply\ capacity\ at\ s$

Pre-fault voltage limit is shown in (4.1) and post-fault voltage limit is in (4.2). The percentage of voltage α is specified with regards to the time period, for example 30% immediately, 25% at 0.10 second after fault.

In NSW, TransGrid is generally expected to plan and develop its transmission network with compliance to N-1 Criterion. Therefore, for inequality constraints related to post-fault in these areas, TransGrid usually conducts joint planning with the DSOs. In contrast to that, part of TransGrid's network in non-urban areas may not able to withstand single fault at time of peak load. Non-urban areas are characterised by a very low load densities, supplied by long, often radial transmission systems. In these areas, curative measures such as under-voltage load shedding are utilized when a fault occurs.

Review of Academic Papers

TPM reported in this section are much more diverse than those mentioned earlier in this chapter. Specific attention is given to the contribution of embedded generation, with forecasting models introduced to not only foresee the energy produced by planned new generation but also to determine the likelihood of the generation connections themselves.

The same probabilistic approach is applied to the network planning initiatives, which are assumed to share a similar level of uncertainty.

Again it must be noted that that in these papers no mention of 'active management of embedded resources by the DSO'. This could lead to a conclusion that both generation and load are assumed to run unrestricted and that in principle real and reactive power values at the interface can be determined by removing forecasted generation from forecasted load.

AN INNOVATIVE METHODOLOGY OF NETWORK PLANNING ON THE GB TRANSMISSION SYSTEM (B. TAN AND L. FU) [9]

This paper describes a concept for determining the likelihood of transfers across system wide boundaries (which divide the network into two areas of similar size). Historically, large variations in transfer results have occurred and this has been as a result of the openings and closures of generation stations.

The probabilistic technique used can be taken further to inform system planners of the likelihood of both conventional and wind generation will be available. The method involves the quantifying of probabilistic inputs through a scoring mechanism which represents potential openings and closures of generation plant in the electricity market.

In addition, the variations of demand and wind output in different areas and seasons, taking into account forecast errors, are also represented.

Probability of Connection (POC)

The probability score is determined by assessing the generation project against five different criteria:

1) consents,

2) finance,

3) government policy,

4) generation technology, and

5) Fuel Type Probability (FTP).

Within each of the criteria, priorities are given to measure their different levels of importance towards the successful completion of the generation project.

Probability of Closure (POCL)

Generation stations are assigned directly scalable factors based on the above five different criteria. This probability is further refined chronologically according to emissions restrictions and age of plant.

Wind farm output modelling

Three major types of wind farm output are listed as being identified in GB transmission system:

1) onshore (not near coast line),

2) onshore (near coast line), and

3) offshore.

Year round mean values of wind farm output fraction factor for the three types are typically 10-21%, 25-35% and 30-40% respectively and these values are then included within the generation background scenarios used by system planners.

PROBABILISTIC APPROACH FOR NETWORK PLANNING COPING WITH SHARP INCREASE OF WIND GENERATION: APPLICATIONS TO THE ITALIAN CASE (M. VALENTE, E.M. CARLINI, D. CANEVER, B. COVA AND D. PROVENZANO) [10]

The paper addresses the impact on the transmission grid as a result of a large amount of wind generation in Italy. This, with wind generation being a non-dispatchable intermittent resource creates power flows that risk saturating the available transmission corridors.

In the paper, an algorithm developed by Cesi Ricerca (a project funded by Italian Government) has been improved and a novel optimisation technique is presented that allows assessing when the resort to active management is truly convenient, which of the distributed energy resource – generators and responsive loads – are to be involved in the active management and at what extent such an innovative operation would be convenient.

The paper describes a generation-transmission system model that is developed to assess, at the planning stage, the impact of wind farms into a meshed network in probabilistic terms. The mathematical model mixes the annual reliability evaluation of the electric network, based on a non-sequential Monte Carlo model, with the wind farm production model to estimate system reliability indexes such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Expected Energy Not Supplied (EENS), subdivided by their causes:

- lack of power of the whole system;

- loss of network transmission capacity (overload);

- loss of network connectivity (islands creation and isolated buses).

The analysis of different network conditions and load levels is achieved considering the system components unavailability rate during a whole year of simulation. Generation dispatching is obtained first of all by a merit order where network constraints are disregarded and only the economic criterion is taken into account; in this operation wind energy has the higher priority (multi area dispatch).

Following this, network violations found are examined to force a re-dispatching primarily on thermal generators and, if not sufficient, on the remaining units; finally, wind farm generation is progressively reduced until a possible cut-off to relieve network congestion. In extreme situations, a final balance is reached removing network overloads by load curtailments.

The model assumes that wind generation is the first to be scheduled for production and the last to be cut-off in case of network constraints (highest merit order). The modelling of wind production is based on measured data covering different years and different measurement locations.

NETWORK PLANNING – METHODOLOGY AND APPLICATION (R. DE DIOS AND P. MARTIN) [11]

The paper presents a new methodology for transmission network planning and its application to the Spanish electricity system.

In the paper, the new methodology and new tool have been developed to help in the planning, which aim to facilitate the definition and prioritisation of the future actions on the transmission network, including but not limited to:

1) construction of new substations and lines;

2) repowering of existing lines (i.e. increasing the lines power carrying capacity); and

3) installation of transformers and reactive power compensation devices.

The tool enables the analysis of contingencies in multiple scenarios of the transmission network, and uses the probability of occurrence of each scenario and each contingency to calculate the so-called criticality and sensitivity indexes, evaluated for each scenario and element.

The planning methodology adopted includes a range of stages aimed at the identification of problems and the proposal of solutions. The process is developed in the following stages: static analysis, dynamic analysis, feasibility of the physical implementation of the projects and application of economic criteria.

The paper continues by describing a tool that has been developed to enable the analysis of multiple scenarios of the topology of the transmission network. The scenarios must comply with the following requirements:

- to cover the expected range of demands in the future period analysed: from the peaks to the extreme off-peaks, passing through the intermediate states.

- to comply with the static technical restrictions of the system (overloads and high and low voltage limits).

- to show the expected variability in the future period in the prices of fuel, hydro condition (wet and dry), wind condition (high and low), international exchanges, etc.

TRANSMISSION NETWORK PLANNING IN IRELAND IN AN OPEN MARKET ENVIRONMENT (A. SLEATOR, N. AMEIJENDA, Y. COUGHLAN, J. KELLIHER AND K. MATTHEWS) [12]

The paper presents an approach taken by the TSO in Ireland to manage the uncertainty in system development using a number of techniques. For example (and of particular relevance to the topic of the JWG) using scenario techniques to develop plans for system development that meet the reasonable needs of stakeholders for transmission of electricity in a safe and economical manner and with due regard for the environment.

Historically, the TSO in Ireland planned the network based on known future centrally planned generation. However, since the introduction of competition, the system is planned by the TSO in a different way as a result of the restructuring of the electricity sector. It is the TSO's responsibility to accommodate stakeholder developments by providing the appropriate network potential. Therefore in addition to the traditional approach of developing the topography of the electricity network to maintain system standards, development must now also facilitate stakeholder needs resulting in increased complexity in the system development process.
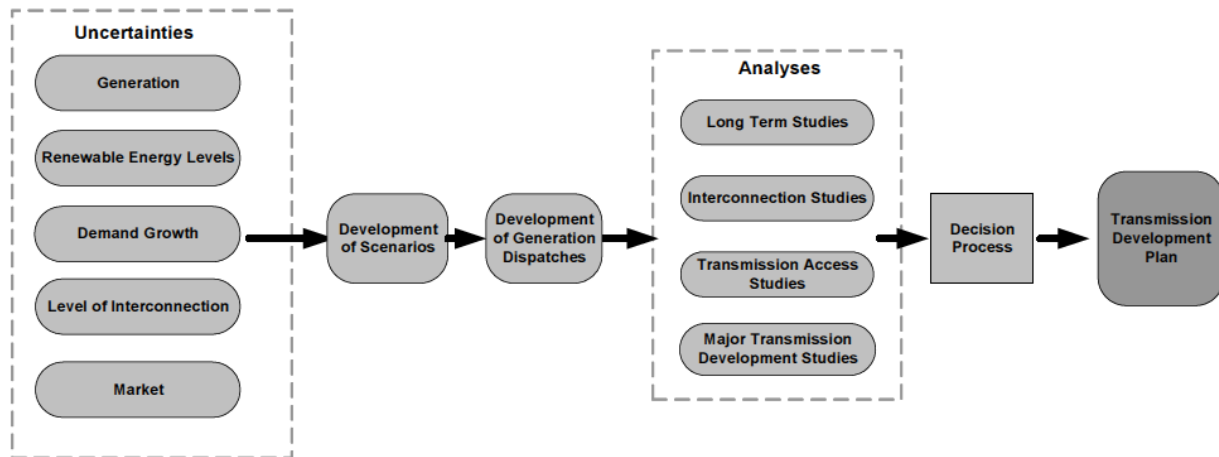
The paper defines the current uncertainties associated with the transmission development process in the new environment, which are listed as follows:

- The TSO can no longer determine the location of new thermal plant, therefore the type, size and location of future generation stations is now a major uncertainty for the TSO.

- Future renewable energy levels (in particular wind energy levels) are subject to evolving government policy.

- The prediction of future demand growth levels may no longer be as accurate as before.

- The location and size of future interconnection with neighbouring power systems is being considered at present. Further interconnection between Northern Ireland and the Republic of Ireland is being progressed. The regulator is also considering the provision of interconnection between Ireland and Great Britain.

- The impact of the electricity market and its effect on constraints is another uncertainty. A single electricity market (SEM) is being put in place for the island of Ireland.

- It has become increasingly difficult to build transmission lines. There can be significant variation in the lead times associated with transmission line reinforcements.

The TSO's objective is to identify reinforcement plans that provide the most benefit over the broadest range of future conditions. The process employed by the TSO for managing the uncertainty involved in the transmission planning process is illustrated in the figure below.

Figure 25: Transmission Planning Process adopted by TSO in Ireland.

The technique used by the TSO in Ireland and described in this paper uses a scenario based approach that is adopted to manage the level of uncertainty associated with transmission development. This is to combat the anticipated high levels of connected wind generation (and other RES), more interconnection and uncertainty over the timing and location of future generation. Its aim is to ensure that transmission planning studies consider a far wider spectrum of futures.

A similar approach is applied by the German TSO. The German power grid development plan can be seen at http://www.netzentwicklungsplan.de/en/content/grid-development-plan.

The chosen scenarios are typically based on a combination of assumptions about future generation, demand growth and levels of interconnection. Each scenario considers a number of generation dispatch configurations. To simulate the variation in generation dispatch, the model tests the network under a wide range of generation dispatches.

These scenarios and dispatches produce a range of network problems and solutions which are then comprehensively analysed and compared. This process facilitates the identification of robust plans that are based on a wide range of scenarios.

FLEXIBLE TRANSMISSION NETWORK PLANNING CONSIDERING DISTRIBUTED GENERATION IMPACTS (J.H. ZHAO, J. FOSTER, Z.Y. DONG AND K.P. WONG) [13]

The paper presents a multi-objective optimisation model for Transmission Expansion Planning (TEP). This is a novel approach that proposes selecting transmission expansion plans that are flexible given the uncertainties of generation expansion, system load, and other market variables.

Catering for uncertainties

The paper presents a number of probabilistic approaches have been proposed to handle random uncertainties such as the uncertainties of load, generation capacities, and generator availability. Decision analysis can be applied to take into account non-random uncertainties. Stochastic programming can be employed to find some policy that is feasible for almost all of the possible data instances and maximizes the expectation of some function that includes both decisions and random variables.

Transmission Expansion Planning

Paper proposes that given the increase in uncertainty the contemporary context, an expansion plan should be selected on the basis of its flexibility. The most flexible plan is defined as the plan that can adapt to any potential scenario at minimum adaptation cost.

The flexibility criterion is chosen because probabilistic and decision analysis methods do not consider the possible consequences of implementing an expansion plan. In a deregulated market, transmission planning usually has to simultaneously satisfy a number of different planning objectives such as: enhancing market competition, improving reliability and security, etc.

Since the implementation of an expansion plan will usually take several years, the optimal plan that is identified by probabilistic or decision analysis methods may not be able to satisfy the planning objectives after implementation due to significant market uncertainties. Further expansion will then become necessary and this cost should be taken into account and used to measure the value of flexibility. Thus, a framework could be for flexible transmission planning with further development to handle more complicated cases.

Overview of the Proposed Planning Method

The major steps of the proposed planning method are listed as follows:

1) Develop models for system load and market price (to be used in later steps to model market simulation).

2) Evaluate potential investment options and select several options that are relatively attractive. These options include both traditional generation techniques and DG.

3) Employ the multi-objective optimization model to generate several candidate expansion plans that are quasi-optimal at the beginning of the planning horizon.

4) For each candidate plan, perform Monte Carlo simulation to generate market scenarios. Each scenario consists of a chosen generation capacity, system load and market price path, and the application of different market rules such as different feed-in-tariff (FIT).

5) For each plan under a scenario, re-expand the network if objectives are not reached and calculate the adaptation cost.

6) Obtain a probability distribution of the adaptation cost of each candidate plan and select the optimal expansion plan based on its flexibility.

Conclusion

Following a detailed literature of TPMs from a number of TSOs and a literature review of relevant technical papers it can be seen that a transmission planning methodology is made up of three main stages: scenario building, transmission planning, and final plan assessment. The literature review conducted in this TB focuses on the first two of these stages.

The reviewed inequality constraints revealed that every region has its own technical standard to define reliable and permissible operation. Both CAISO and AESO apply WECC and NERC standards as a base for their assessments. Each TSO then takes these standards and expands on them individually. National Grid applies different N-X contingency requirements based on how much load is supplied by a substation. The German TSOs have different regional thermal equipment limits. TransGrid applies different reliability requirements based on different areas in addition to the N-1 reliability criterion which is commonly applied by all covered TSOs.

The review of recently published academic papers available from international publications showed that many organisations are developing models for which the objective is to cater for increasing levels of uncertainty relating to generation expansion, system load, and other market variables.

The models described in within the literature review then build a number of scenarios across a wide spectrum of years. These scenarios will be based around assumptions made on; expected generation levels, renewable energy levels, demand growth, level of interconnection and market behaviours.

Some of the models are expanded further to include Monte Carlo simulation to cater for different market scenarios. The scenarios that these models produce are extended to include market price path, and the application of different market rules and are used to optimise the dispatch patterns for generation in order to try to resolve the network violations found.

These scenarios are then used as the basis of transmission planning assessments the output of which forms the basis of the Transmission Development Plan.

Within all this diversity among established/innovative models, the absence of any reference to DSOs' influence on embedded resources (not to mention a model of this influence according to its possible strategies) is interesting.

If we assume this implies P, Q values at TSO/DSO interface are going to be determined in the near future according to historical data as measured at the boundary point or - on the other hand - they result from the combination of unrestricted values of individual load/generation data of connected network users, it is very likely (or, at least, it cannot be excluded) that this way of neglecting the "active management" functionalities may endanger system security (in the former case) or lead to overinvestment (in the latter one).

INNOVATIVE PLANNING METHODOLOGIES SWOT/GAP ANALYSIS

This section includes deliverable 5 of the TB: "An overview of potential adequacy of innovative planning methodologies within the same predefined scenario".

SWOT Analysis

The key strengths, weaknesses, opportunities and threats to the planning methodology have been updated based on the innovative methodologies identified and are summarised in 7 below.

Table 7: Updated SWOT Analysis

Strengths	Weaknesses

• Relatively simple base electrical model required with known variables. Processes are in place to ensure values remain known to those performing planning studies.
• Systematic/repeatable methodology used to identify extreme network cases and required contingencies
• Generally planners have known limits (examples being voltage and thermal loading of plant) that define the acceptability of results defined by documents such as the 'Grid Code'
• Probabilistic behaviour of DER and their development can be account for
	• Reliant on accurate forecasting of:
	   o load growth and or reduction
	   o generation line ups
	• No algorithms are proposed to describe 'active' management of embedded resources by DSOs.
	• Different SOs have different priorities altering the direction of the studies
	• There are a great number of uncertainties to be considered
	• Proposed new solution methods involve increasing the number of scenarios to be examined which in turn increases the effort required to identify required solutions

Opportunities	**Threats**
• The spread of solutions that can be generated allow for a semi-optimal solution to be found for a range of potential outcomes that can then be refined once the event comes closer on the planning horizon • Increased input from the DSO could include outputs from their system analysis reducing the strain on the TSO to identify the cross boundary flows	• The number of simulations to be run increases, as the worst possible cases result from a higher number of intersections between load and generation scenarios • Probabilistic forecasting for long term planning cannot fully account for political influences or financial market behaviour which can have major impacts on how DER is realised

GAP Analysis

Following from the processes identified previously, the literature review has identified those methods for accounting for the uncertainty in DER outputs and connection of new schemes are available. This means that DER can be introduced into system models for long term planning with greater certainty in the accuracy. What the literature cannot show is the method to exchange the information required to perform this analysis. This procedure to bridge the gap needs to be driven by the TSO or the appropriate authority in its locality.

If the proposed methodologies are adopted the desired future state of being in a position to be able to guarantee a secure and affordable network planning allowing for greatly increased DER may be achieved by planners.

CASE STUDY – NATIONAL GRID (ENGLAND & WALES)

Background

National Grid owns and operates the transmission system in England and Wales and also operates the system in Scotland. In Great Britain, the connection process and operation of electricity generators varies depending on which country's (Scotland / England and Wales) transmission or distribution network they connect to.

In England and Wales, the generators could be either connected directly to the transmission network or as embedded generators within the distribution network. The generators more than 100 MW capacity are categorised as 'large', whereas, the 50 – 99 MW and 1 – 49 MW capacity generators are categorised 'medium' and 'small' respectively. Large generators are required to have an agreement with National Grid for both, either connecting directly to transmission network or as an embedded generator within Distribution network.

Small and Medium generators connecting within Distribution network which do not require explicit access rights to the National Electricity Transmission System (NETS) are not required to have an agreement with National Grid. However, if the Distribution Network Operator (DNO) believes that the proposed connection may have an impact on the NETS, then the DNO will apply to National Grid for a Statement of Works (SOW).

If National Grid identifies any impact on the transmission network, then a SOW response will indicate the works required. If the generator wishes to progress with the connection, the DNO would then apply to National Grid for a Project Progression. National Grid would then carry out the necessary further system assessments (if required) and send an 'Offer' comprising of a Construction Agreement and Technical Appendices outlining the Grid Code requirements to the DNO. The DNO will then prepare its own agreement and send the 'Offer' to the generator. If the generator accepts the DNO offer, then the DNO must sign the offer from National Grid.

Problem

The above mentioned process worked well up to the last few years as the number of small embedded generators connecting in the Distribution networks was very low. For some DNOs it was as low as only one or two SOW applications a year. However, in the last couple of years, the DNOs across England and Wales, especially in South East, South West and South Wales region, saw a huge increase in the volume of embedded (mainly small) generation connection applications. This meant that processing the individual SOW application for each of the generators soon became unmanageable for both DNOs and National Grid. It also became very challenging for National Grid to carry out the necessary system studies to correctly identify the impact on transmission network in the short timeframe (28 calendar days) and with limited information about the generators.

Solution

Following the dramatic growth in the embedded generation connection application experienced in 2014, a new SOW process was developed by National Grid through industry consultation. The revised process allows the DNO to apply for a SOW to National Grid for several embedded generators connecting within a Grid Supply Point (GSP) for which the DNO has an agreement with National Grid. It also allows the DNO to submit SOWs for several GSPs within a region at the same time.

A new data spreadsheet has been developed which all DNOs need to complete as part of their SOW application. It was envisaged that the impact on the transmission network due to growing embedded generation would be worst for a scenario with minimum demand and maximum EG output. The data to be provided includes the net P (MW) and Q (MVAr) flow at the DNO Bulk Supply Points (BSPs) within the GSP for two periods – morning period and midday period – pre and post connection of the proposed embedded generators included in the SOW application.

For the morning period, to get the net P and Q flow at a BSP, the DNO will use the morning period minimum demand and apply a suitable scaling factor to Solar PV embedded generators output but take 100% contribution from the other generators within the BSP.

For the midday period, the DNO will use the midday minimum demand with 100% output from all the embedded generators within the BSP. Figure 26 below shows the example of the P and Q data received for a GSP for the

Midday period. Node data information includes the node names and operating voltages for all the BSPs within that GSP.

GSP	National Grid Diagram	DNO Node Name	National Grid Node Name	Operating Voltage (kV)	Pre Connection Load Flow BSP PQ at GSP Mimimum (27/06/15 @ 16:00) Power BSP Demand (-ve = Net Generation)				Post Connection Load Flow BSP PQ at GSP Minimum (27/06/15 @ 16:00) Power BSP Demand (-ve = Net Generation)				Adjustment to Load Flow BSP PQ at GSP Mimimum (27/06/15 @ 16:00) Power BSP Demand (-ve = Net Generation)			
					MW	Mvar	MVA	PF	MW	Mvar	MVA	PF	MW	Mvar	MVA	PF
WBUR	180	LINC3J	LINC31	33	-29.60	6.40	30.28	-0.98	21.00	5.30	21.66	0.97	50.60	-1.10	-8.63	-1.95
WBUR	180	LINC5J	LINC51	11	16.00	4.01	16.49	0.97	16.00	4.01	16.49	0.97	0.00	0.00	0.00	0.00
WBUR	180	WORK3J	WORK31	33	22.00	5.51	22.68	0.97	2.40	8.90	9.22	0.26	-19.60	3.39	-13.46	0.71
WBUR	180	KYGN1J	KIRG11	132	-40.00	0.00	40.00	0.00	-40.00	0.00	40.00	-1.00	0.00	0.00	0.00	1.00
WBUR	180	FALA1J	FALA11	132	2.00	0.00	2.00	0.00	-50.00	0.00	50.00	0.00	-52.00	0.00	48.00	0.00
													TOTALS:	-21.000	2.286	25.912

Figure 26: P (MW) and Q (Mvar) data example

DNOs also have to provide the fault infeed information for each BSP pre and post connection of the proposed embedded generation connection(s). Figure 27 below shows the example of the fault infeed data received for a GSP. Fault infeed information includes the sub-transient and transient fault current RMS values in kA. It also includes the X/R ratio for each of the BSP within that GSP.

GSP	National Grid Diagram	DNO Node Name	National Grid Node Name	Operating Voltage (kV)	Pre Connection Load Flow BSP Fault Infeed Short Circuit			Post Connection Load Flow BSP Fault Infeed Short Circuit			Adjustement to Load Flow BSP Fault Infeed Short Circuit		
					Sub-Transient I'' (kA RMS)	Transient (120ms) I' (kA RMS)	X/R (G74 Method 'C')	Sub-transient I'' (kA RMS)	Transient (120ms) I' (kA RMS)	X/R (G74 Method 'C')	Sub-transient I'' (kA RMS)	Transient (120ms) I' (kA RMS)	X/R (G74 Method 'C')
WBUR	180	LINC3J	LINC31	33	7.703	4.560	5.343	7.009	3.900	5.343	-0.694	-0.660	0.000
WBUR	180	LINC5J	LINC51	11	3.253	1.289	4.809	3.257	1.290	4.806	0.004	0.001	-0.003
WBUR	180	WORK3J	WORK31	33	1.481	0.136	3.078	2.845	1.520	4.548	1.364	1.384	1.471
WBUR	180	KYGN1J	KIRG1J	132	0.204	0.204	45.455	0.204	0.204	45.455	0.000	0.000	0.000
WBUR	180	FALA1J	FALA11	132	0.850	0.850	40.000	7.351	5.961	42.500	6.501	5.111	2.500

Figure 27: Fault Infeed (kA rms) data example

Figure 28: Generator Information data example

Figure 28 above shows the example of the generation information received from the DNO with their SOW application. This data table provides some of the key and essential information such as the connection status/date, fuel type, generator name and location (geographical co-ordinates and postal address), generation capacity and the connection node (BSP). DNOs can also indicate if any of the proposed embedded generators from previous SOW applications have now dropped out.

The revised SOW process and better EG data has enabled National Grid to carry out SOW assessments in an efficient manner. It also allowed improved assessment of the impact on the transmission network focussing on

individual GSPs as well as wider regions such as the South East and South West regions. National Grid can now better inform DNOs and the aspiring Embedded Generators of the head rooms available at individual GSPs and on the wider transmission network.

CONCLUSION

This section includes deliverable 6 of this TB: "A recommendation on steady-state planning methodologies for HV networks hosting significant DER, in terms of algorithms and datasets to be used".

Findings from the JWG

The JWG C1.29 was created to investigate the growth of DER and highlight the implications for planners, the output of which is this brochure detailing a "future-proof" demand planning criteria for Transmission Networks.

The TB looked into the growing challenges that face the current electricity system associated with the increasing penetration of DER and discussed the importance of being able to maintain the current levels of security and quality of supply during varying operational conditions.

The brochure carried out an assessment of traditional and "state-of-the-art" methodologies for transmission system planning. The task involved collecting information about current practices adopted by TSOs with specific regards to the information that interfacing DSOs presently bring to support transmission system planning.

This involved creating and distributing two questionnaires to various TSOs and DSOs with a view to collating information about the levels and types of data exchange for the purpose of undertaking transmissions system planning.

The responses from Questionnaire 1 showed some interesting statistics across the different questions. For example, 80% of all responses exchange the amount of demand transfer that can be carried out at MV and LV voltage levels but only 40% of responses exchange reverse power capability of the TSO/DSO interface points. Similarly, 90% of responses provide a total MW value of existing connected generation with 60% of those responses being divided by fuel type whilst for new potential connections only 70% of responses exchange this information with as little as 21% of all responses providing this divided by fuel type.

A recommendation as part of this JWG and TB is that the future provision of such data exchange between more TSOs and DSOs will allow network planners to better understand the current situation and plan for a number of equally probably scenarios. The scenarios would take account of levels of generation, fuel type and likely expected seasonal variation of output. This task also involved carrying out a methodical exercise using a SWOT matrix coupled with a GAP description in order to characterise existing methodologies in terms of adequacy towards novel context elements. This methodology was carried out following the data collation task and then again following the literature review of academic papers and current practices of TSOs.

The analysis from Questionnaire 2 indicated that 75 % of the TSOs that responded to the quesstionnaire are able to curtail renewable generation if necessary to avoid the need to invest in reinforcements. This conclusion is supported by the responses for the ranking of operational cost, capital cost and compliance, as well as 100% of responders including operational costs in their planning process.

The analysis carried out shows that the current practices are largely reliant on accurate forecasting of change in demand and generation and as a result, they assume no significant change in behaviour in the planning period. It was also demonstrated that the existing agreements with DSOs and other network users requires a certain level of information to be exchanged up to and included more data information on DER due to current lack of visibility in this area.

The second part of this analysis carried the findings from the literature review and this showed a number of additional strengths and opportunities that can be fed into the current practices used by TSOs and DSOs. For example, the adoption of the probabilistic nature of contingencies and behaviours of DER and their development can be accounted for as part of the steady state simulations. This will allow network planners to assess the impact of an event happening but then allow them to couple that with the probability sequence of events lining up. Whilst the perceived risk documented in this TB is that this will require more simulations to be carried out and therefore more effort required to identify required solutions, it is believed that the benefits of being better able to design and build a cost-effective and efficient transmission system far outweigh this.

Comparisons can be drawn from both of the questionnaires and the literature review of innovative transmission system planning methodologies. For instance, half of the responses stated that as part of the transmission system

planning methodology adopt 3 – 5 scenarios of study. The use of scenario based planning is referenced in a number of papers within the literature review section of this TB and incorporating the probabilistic behaviour of DER and their development can be accounted for within these scenarios.

Recommended Next Steps

No reference was found to active management of the embedded resources by DSOs. As these functionalities are available today and will affect in the short-term distribution sub-systems behaviours as observed by TSOs, it is recommended that models and algorithms are investigated in order to represent the effect of dispatching actions by DSO according to sets of possible strategies (e.g. reduction of joule losses, reduction of reverse energy flows, reduction of energy injection from TSO, etc.). This will allow optimal sizing of infrastructure avoiding unplanned, and therefore useless redundancies from one side, and unexpected shortage of grid on the other.

Within this JWG the limitations were set to focus on planning rules between transmission and distribution and therefore this has opened up further opportunities for additional research in the following areas:

- Additional research into generation mix in DER and what this means for transmission system planning. There are many different types of distributed generation (PV, Wind, Battery etc.) and the mix of these will impact on the scenarios that need to be considered for future proof planning rules. Understanding the mix and the impact this has on the networks will allow more detailed analysis to be carried out on the required planning rules.
- The commercial aspects for Active Network Management (ANM) schemes and the economics of constraining generation to avoid the need to reinforce a TSO/DSO interface.
- New technology that is likely to connect and how they will be used and how they might affect this. We have seen a large rise in wind, and more recently PV. It will be beneficial to determine what is on the horizon (e.g. batteries, electric vehicles) and how this will affect the power flows across the DSO/TSO interface.
- Regulatory accountabilities for TSO/DSO interface such that the DSO can manage the transfer of power within their own control rather than rely upon the TSO.

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