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Planning Criteria for Future Transmission Networks in the Presence of Greater Variability from Distributed Generation

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SUMMARY

Today's electricity system planners face growing challenges trying to accommodate the increasing penetration of Distributed Energy Resources (DER) while maintaining the security and quality of supply. Varying operational conditions such as failures in embedded generation, distribution network faults, excess generation in non-peak or maintenance periods introduce additional factors that further complicate the planning process. In addition, the use of interconnection with other grids and the deployment of smart grid technologies amplify the planning challenges.

Traditional planning procedures use historical data to predict the net power exchange between Transmission System Operators (TSO) and Distribution System Operators (DSO) with DER growth usually being incorporated in the demand forecast. Such an approach does not seem plausible any more as it could result in under- or over-investment in reinforcing the transmission network and, as a consequence, in compromising the security of the system or in rising required expenditure to unacceptable levels.

This paper investigates the historical methods of data exchange between TSOs and DSOs and discusses why they may be insufficient for steady-state planning of transmission networks under the conditions described above. Furthermore, it looks at what future exchanges of data may be required and how they should be utilised to create more robust planning techniques.
An assessment of the traditional as well as more innovative transmission network planning techniques has been conducted to verify their adequacy to guarantee secure and affordable network planning. The information has been collected from chosen network operators,

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relevant CIGRE papers and publically available literature and analysed using SWOT matrices coupled with GAP descriptions.

The study showed that the conventional planning practices rely on the accuracy of methods used to forecast demand and generation and that there is no provision for behaviour variations during the planning period. It is also clear that given the TSO's lack of visibility in the sub-systems connected with their network the existing data exchange agreements need to be revised and include detailed information on DER connected such as seasonal variations and fuel type.

The paper is also looking at more innovative techniques, elements from which could be incorporated into the existing planning practices deployed by TSOs and DSOs. One of the most promising elements is the adoption of a probabilistic approach with regards to contingencies and behaviours of DER connections and generation. Such an approach would allow planners to assign risk factors to events and sequence of events that need to be taken into account in the planning process. Although this method would significantly increase the required work and effort its benefits would be much more significant in the process of designing and building a reliable and economic transmission system.

Finally, the paper concludes that additional benefits could be realised should the DSOs be incentivised to manage their network and power flows. A more active management approach could result in minimising the required investments at the transmission network although it could also reduce the ability of the TSO to forecast future demand and generation unless more robust data exchange frameworks are in place.

KEYWORDS

Renewable Energy Sources, System Planning, Transmission System Operators, Generation Curtailment, reliability, security of supply, Distributed Generation, Distribution/Transmission interface, Active Distribution Network, Regulation.

INTRODUCTION

The scope of this paper is to highlight the impact of an increased level of DER at Medium Voltage (MV) and Low Voltage (LV) levels on steady-state system planning at Higher Voltage (HV) levels. The content of the paper is largely based on a Technical Brochure produced by the Joint Working Group (JWG) C1.29 [1].

System planning is carried out in order to determine the most cost effective solution to changes in the network caused by a number of various sources (changes in generation and demand, new connections etc.) in order to maintain system security and continuity of supply. System planning traditionally looks at future scenarios and tries to predict trends in order to determine the optimum time to intervene such that costs are minimised. This paper explores what changes, due to large levels of distributed energy being connected at the MV and LV levels (wind, solar etc.), is having on system planning and questions what future system planning criteria should be in order to minimise the risk of over-investment and ensure appropriate system security.

Steady-state HV planning is performed using 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 under which condition, network parameters exceed given boundaries (e.g. maximum thermal capacity of feeders, voltage drops in nodes, and so on). In case of violations, interventions are identified and scheduled according to the year in which the criticalities arise, to maintain/restore acceptable conditions.

The most important input data for load flow calculations is, without any doubt, represented by load and generation in the HV nodes. The main 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 sum of their unrestricted individual behaviours.

When this is considered, along with the assumption that historical data represents a combination of both past behaviours and assumes no significant changes are going to happen in the planning period, this allows the use of historical data and further extrapolation of their time series. This allows a system planner to perform accurate evaluations of HV network adequacy for future conditions and in doing so, the effect of the increase in the number of connected users. This is because the measured values capture both increase/decrease of connected customers and increase/decrease of individual consumption/injection.

An increase in the amount of DER connected to MV and LV networks, though significant in quantitative terms, doesn't really challenge this model, as this kind of contribution can still be managed in a conventional way.

Under this model, 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 coefficients, etc.) to add up all load and generations reference data.

No doubt this change of model 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".

COMMON PRACTICES OF TRANSMISSION NETWORK PLANNING

This section discusses common practices adopted by TSOs worldwide with particular attention to the information shared between the TSOs and the interfacing DSOs. The discussion is based on results from a recent study.

Recent rapid growth in DERs has strongly affected the transmission network planning therefore it is vital that TSOs and DSOs work together to deliver a safe and reliable transmission and distribution networks.

Obtaining relevant data to build scenarios with various uncertainties is the key to transmission and distribution network planning.

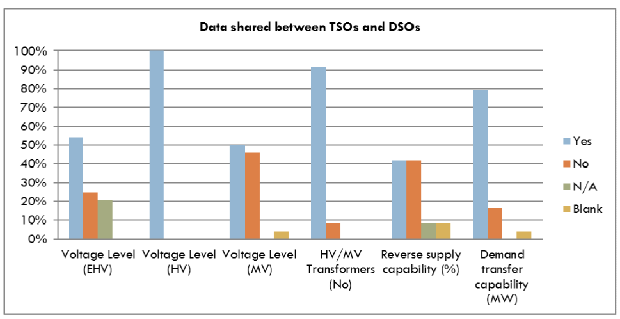

Figure 1: Types of data shared between TSOs and DSOs

Figure 1 shows the type of data exchanged between TSOs and DSOs. At present TSOs and DSOs exchange only the most crucial data such as Voltage levels, transformer data and historic/forecast generation and demand. Renewable Energy Sources (RES) are highly unpredictable. With more and more RES being connected to the network and the redundancy of conventional generation sources means that there is a greater uncertainty in the supply and demand. 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. Results indicate that only 50% of the respondents exchange reverse power flow capability with their counterparts. While reverse power flow is an unlikely scenario in urban areas it could become a serious problem in rural areas where the embedded generation is high.

Figure 2 shows load and generation data exchanged between TSOs and DSOs. The system planning engineers require a greater transparency of load/generation data in order to ensure sufficient network transfer capacity without wasting resources on excessive network redundancy. Failure in obtaining accurate load/generation data can lead to under/over investment on the electricity

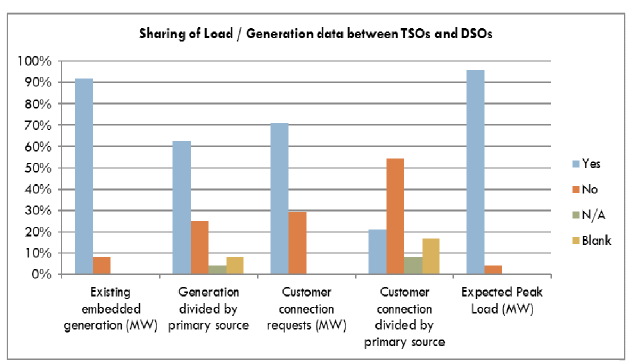

Figure 2 Types of Load/Generation data exchanged between TSOs and DSOs

network and inaccurate demand forecast.

The majority of the TSOs and DSOs exchange historical and forecasted maximum active and reactive power as this data determines the transmission network capacity and also provides a good justification for their investment strategies. More than 50% of the respondents also exchanged the historical and forecasted minimal active and reactive power which is important in assessing reverse power flow and high voltage issues.

Security of supply ranked as the most important aspect of the transmission network planning. It is TSOs' duty to provide reliable and efficient power supply to their customers by appropriately managing ever changing supply risks. TSOs must have access to sufficient generation capacity to supply the demand at any time to avoid power shortages.

As shown on figure 3, TSOs consider various fault types in their contingency planning. All the TSOs design and plan their network to accommodate a single circuit fault in order to comply with N-1 criterion. Even though the probability of double circuit faults and busbar faults occurring are low they have a knock-on effect on the network operation therefore is taken into account by the majority of the respondents.

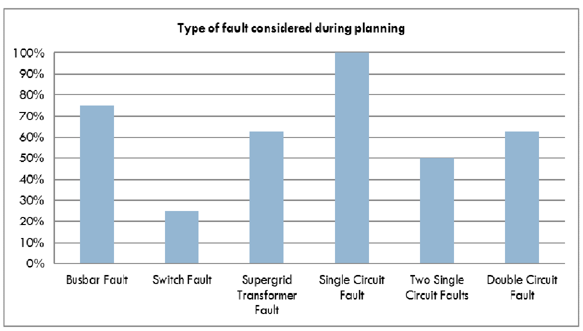

Figure 3: Types of faults considered by TSOs during system planning

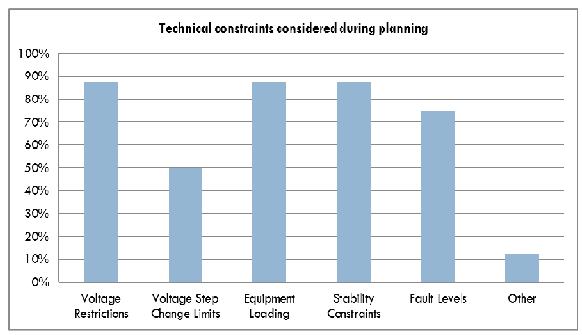

Figure 4: Technical constraints considered during planning

Technical constraints play a crucial part in ensuring a reliable and secure network operation. Figure 4 shows that stability constraints, voltage restrictions and equipment loading are the most vital technical constraints considered by TSOs. In addition, certain TSOs also consider power quality issues such as unbalance and harmonics in the transmission planning process.

With the growing number of RES connections it is essential that accurate RES generation forecast is used in preparing the daily network operation, especially for system worse case demand scenarios: summer minimum and winter maximum. Only 30% of respondents are able to perform accurate RES forecasts. One of the TSOs relies on RE generators to provide the forecast whereas two other TSOs rely on Balance Responsible Party to provide this information. Five out of eight respondents have an online database of the RE generation connected to their control areas. The ability to curtail intermittent renewable generation is becoming important to balance the supply and demand and maintain an uninterrupted power supply. Although 75% of the TSOs are able to curtail RES it is evident that majority of the TSOs heavily rely on the DSOs to control RES generation in the DSO networks to avoid adverse effects on TSO networks. The responsible party for the curtailment cost largely depends on the regulatory regime of each country.

RES generation certainly diversifies the current generation mix but it requires better management and better integration to the existing power grid. TSOs and DSOs must continue to work together to create a greater transparency in each other's planning methods to overcome the challenges created by RES. It is evident that better communication between TSOs and DSOs will improve the reliability of information shared between the counterparts resulting better system modelling and accurate security of supply assessment. Also it is equally important that TSOs and DSOs work with RES generator operators to make sure the smart use of RES generation along with the conventional generation methods to balance the supply and demand.

COMMON PRACTICES OF DISTRIBUTION NETWORK PLANNING

Recent research has gained feedback from five European DSOs on their planning practices. Due to the small number of respondents, the conclusions in this paper show tendencies. If general conclusions are to be drawn, a larger number of respondents will be required.

In general, DSOs are mainly focused on the service they need to provide to their end customers and rely on the TSOs to ensure overall system stability and reliability:

- Compliance to standards is generally the main issue, as it is considered as the main driver in detecting network criticalities in steady-state planning
    - 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
        - The expected number of scenarios being analysed is three, but the actual number largely depends on the degree of uncertainty.

- Investment costs are highly considered in HV planning;
    - cost of altering dispatch and of curtailment of DER are not normally considered
    - differences appear when it comes to losses and operational costs, likely due to national/regional Regulations
    - capital costs and cost of supply interruption are always considered

- Security of supply and reliability are interpreted differently by different DSOs as these two issues are defined by their respective planning rules.

The extent and the way in which DSOs can play their role in managing RE varies in different utilities and in different countries according to the existing regulations. It was found that:

- Distribution system operators do not always perform forecasts about the output from Renewable Energy (RE) generation.
    - The smaller and more disperse the generation connected (i.e. Germany and Italy), the more likely the DSO is to perform forecasts by itself.

- Online 'live' data is generally available on RE output but mainly reported with reference to MV or "significant" generation plants.

- Curtailment is foreseen and performed according to national regulation.

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

- Compensation for curtailment, if any, is allocated to the originator of the curtailment need.

HV network planning performed by a DSO does not significantly differ from TSO planning for the same network, as far as the steady-state perspective is concerned. Planning practices and system priorities are slightly different from the ones highlighted by TSOs. This is likely due to the respective roles' overall priorities, which inevitably lead to focus in different areas.

As the process is so similar it has similar strengths and weaknesses to TSO planning for being in a position to be able to guarantee a secure and affordable network planning 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.

Nowadays, however, the increasingly adopted approach of active operation of distribution networks (Active Network Management – ANW) allows DNOs to manage the high number of flexible resources such as generators, storage facilities, and demand side management. Their objective is to optimise power flows within their network which may inevitably result in minimising the power exchange at the transmission-distribution interface. Furthermore, actions taken by the DNO would be impossible to forecast and take into account during the planning process rendering the TSO blind to conditions at lower voltage levels.

By incentivising the DSO to perform scenario analysis at their transfer points with the TSO the burden of analysis could be more evenly split across the parties. This though would require the DSO to either have a better understanding of the RE management strategy or shift the burden of control onto them. As mentioned above, there are examples (in the UK both WPD and SSE operate ANM schemes) of the DSO managing RE to satisfy their system constraints so it is conceivable that the role could be extended to manage upstream TS constraints.

CASE STUDY

National Grid owns and operates the transmission network in England and Wales and operates the system in Scotland. In England and Wales generators greater than 100 MW capacity are categorised as 'large', whereas, the 50 – 99 MW and <50 MW capacity generators are categorised 'medium' and 'small' respectively. Large generators are required to have an agreement with National Grid regardless of where they connect – 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 transmission network, then SOW response to the DNO will indicate the works required. After further discussions between DNO and the proposed embedded generator(s), if the generator(s) wishes to progress with the connection, then DNO would apply to National

Grid for a Project Progression and National Grid would then issue a formal Bilateral Connection Agreement to the DNO.

Up until few years back the number of embedded generators connecting in the Distribution networks was very low and the generator development timescales was in years. So the SOW process outlined above worked well. However, in the last couple of years, the DNOs across England and Wales saw a huge increase in the volume of embedded (mainly small) generation connection applications with development timescales in months rather than years. This meant that processing the individual SOW application for each of the generators soon became unmanageable and soon National Grid lost the visibility of the volumes of embedded generators connected to the system. This meant that carrying out the system studies identifying the impact on transmission network and efficient network planning with limited information about these generators became very challenging.

Following the dramatic growth in the embedded generation (EG) connection application, in 2014/15 a new trial 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. 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. To get the net P and Q flow at a BSP, the DNO will use the minimum demand for that period and take 100% contribution from the embedded generators within the BSP except for Solar PV which will be scaled (~5%) for the morning period. DNOs also have to provide the fault infeed information (sub-transient and transient RMS fault currents, X/R ratio) for each BSP pre and post connection of the proposed EG connection(s).

In addition, DNOs now also provide generators' information with their SOW application which includes the connection status/date, fuel type, generator name and location (geographical co-ordinates and postal address), generation capacity and the connection node (BSP).

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 headroom available at individual GSPs and on the wider transmission network. There is also a process set-up to contractually manage the change within allowed headroom without having to go through the SOW process thus speeding up the connection of the embedded generator.

CONCLUSION

The research covered in this paper shows some interesting statistics. For example, 80% of 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 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.

The analysis showed that about 75 % of all respondents are able to curtail renewable generation if necessary to avoid the need to invest in transmission or distribution reinforcements and this is supported by the responses for the ranking of operational cost, capital cost and compliance and 100% of responses 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 including more information on DER due to a current lack of visibility in this area.

The second part of this analysis 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 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.

Finally, we are seeing ANW schemes being more commonly used, which drive DSO's down the path of managing the interface between generation and distribution and therefore minimising under or over-investment in this area. Focussed regulation on this could play a significant part in ensuring the Transmission/Distribution interface in the future is sized appropriately for the services required by each party.

BIBLIOGRAPHY

[1] Joint Working Group SC C1-29 CIGRE. “Planning criteria for future transmission networks in the presence of a greater variability of power exchange with distribution systems”