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Methods and Tools for Planning the Future Power System: Issues and Priorities

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About this report

The Institution of Engineering and Technology was commissioned by the Council of Science and Technology (CST) to research the emerging challenges for modelling electricity systems and how Britain's capabilities would need to be adapted to assess electricity system resilience as GB makes the transition to a low carbon electricity system.

This project commissioned, and received, fifteen individual papers from GB-based specialists of international standing in power system modelling. The authors of the papers worked with a wide stakeholder base of network companies, academics and others, who provided review and challenge. Professor Graham Ault CEng FIET was contracted to provide technical co-ordination and drafting. The emerging conclusions were further validated by means of an industry and academic workshop sponsored by Government Office for Science. The entire project was conducted under the direction of an independent steering committee composed of senior IET Fellows, two of whom were also CST nominees.

The report is composed of three parts:

- Part 1: Main report
- Part 2: Summary of Commissioned Papers
- Part 3: IET Special Interest Publication – Academic & Industry Papers

All three parts of this report are available from the IET website at:

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EXECUTIVE SUMMARY

This report contributes to discussion of the nature of the future power system in the context of the IET's 'Power Networks Joint Vision' initiative. It summarises a number of future challenges arising from the changing nature of generation and demand and the possibility of greater demand-side participation in electricity markets. It argues that these require significant change in respect of current practice in the assessment, planning and development of power network facilities enabling future system operation. It reflects on methods and tools used by network planners in Britain today and discusses areas in which modelling capability needs to be developed and enhanced data or user competencies are required. In particular, although the basic tools currently used by transmission planners are generally adequate, there are already challenges in respect of modelling of wind farms and HVDC converters and in the maintenance and exchange of data. Methods habitually used by distribution planners, while generally adequate in the past, have not so far kept up with developments in respect of connection and operation of generation embedded within the distribution network.

Some case studies are provided in respect of existing software tools ('Assess' and 'ESPAUT') and planning methods (as used in planning of the Western HVDC Link). It is noted that, at a transmission level, some methods and tools have been developed in the past that would have provided much but not all of the capability now required in respect of modelling of system responses and dealing with uncertainty. However, neither the user base nor the software have been maintained.

Conclusions are drawn and recommendations made under the following headings:

1. management of and access to data;
2. the provision of methods and tools to allow the engineering questions to be addressed as conveniently as possible;
3. decision making frameworks;
4. provision of adequate skills among network planners and decision makers to manage data, use new tools and make decisions.

Among other things, it is recommended that:

- work is undertaken to improve the sets of generation and demand data available to planners;
- methods, models and tools are developed to permit sufficient but not over burdensome evaluation by planners of system operational performance using, for example, time series data and suitable representations of system responses to disturbances;
- access to data and standards are widened enabling independent research to complement what is done by utilities and contribute to innovation; and
- quantification of risk is used to underpin investment decision making, and methods and tools developed to permit decision making under uncertainty.

The benefits of 'smarter' power systems with a reduced need for primary assets will not come for free; utility managers and regulators that make judgements on reasonably incurred costs need to recognise the cost not only of the physical facilities to provide new system controls and the contracts with different system actors that provide services but also the cost of new tools and the human resource cost of highly skilled engineers capable of using tools and making prudent recommendations on future network investment. Moreover, the education and research base needs to be maintained in order to provide underpinning expertise to utilities and contribute to information on emerging opportunities and threats, not only to deliver 'innovation projects' that promise to provide immediate cost savings to customers.

It is noted that implementation of the recommendations would depend not only on action by network utilities and their contractors but also, in a number of cases, by the regulator. A final recommendation is that, in light of the relative advancement of some ideas emerging elsewhere, the opportunities for learning from international forums such as CIGRE and European research projects should not be neglected.

1. INTRODUCTION

'Planning' of a power system concerns preparation for or facilitation of system operation [1]. This paper is mainly concerned with long-term planning, i.e. in timescales in which decisions concerning investments in new facilities are made, and the process of 'system development'.

The Technical Report of the 'Power Networks Joint Vision' panel established by the IET [2] set out the broad regulatory and commercial context for investment planning on Britain's power networks. It highlighted some particular challenges for future planning.

1. Renewable generation is intermittent and not as dependable as fossil fuelled or nuclear plant and, in many cases, cannot be scheduled or controlled.
2. The net demand observed at points of connection between transmission and distribution networks, i.e. at grid supply points, will be subject to general demand changes and the growth and operation of distributed generation, i.e. generation embedded within the distribution network. Current industry processes in Britain are inadequate for the collection and sharing of relevant data.
3. There are new analytical challenges in respect of utilisation of new data sources and assessing the effects of variable output from low carbon generation and new controls such as demand side management and active distribution network management.

Electric vehicle charging and more electric heating are likely to be of particular importance in shaping future demand.

The investment planner is largely responsible for specifying and procuring the physical facilities necessary to enable new controls which, in general terms and in comparison with pre-disturbance, preventive adjustment of the system state, promise to allow greater reliance on post-event corrective actions to manage disturbances such as fault outages. That is, were 'credible' contingencies to occur, the consequences would be kept within acceptable limits by corrective actions without the requirement for preventive actions except to make the new system state correctable in the face of any further disturbances.

This paper discusses models used for system planning and the extent to which they are suitable to address investment for future power system operation.

It reflects briefly on methods and tools used by system planners in Britain and discusses areas in which modelling capability needs to be developed and enhanced data or user competencies are required.

The paper is structured as follows. First, there is a reflection on the main drivers for investment in power network facilities and the role of planning standards; then, there is a summary of methods and tools that are currently in use in Britain; next, a review of key challenges is presented followed by a discussion of those challenges and how they might be met. Finally, some conclusions and recommendations are presented. In the appendix, three case studies are given as illustrations of planning of new technology and the use of new analytical methods and software.

2. DRIVERS FOR INVESTMENT IN THE NETWORK

2.1 Total cost of the network

The total costs of a power network may be described as constituting three parts [3]:

- the cost of network infrastructure;
- the cost of operating the system in the delivery of power including the impact of the network in restricting use of the cheapest generation and the cost of losses;
- the impact on consumers of supply unreliability.

These three terms may be denoted by the symbols I, O and X respectively so that the total cost of the network is I + O + X. The most efficient network service is one in which the expected total cost I + O + X is minimised over some given period of time (with some discounting of future costs), i.e. the goal of the network planner is to minimise this total cost and they should identify and undertake any investments appropriate to that end.

As well as providing adequate power quality, a network operator will be concerned with the sustainability of operation of the network infrastructure, in particular that current, voltage and stability limits are observed. The system's state is 'adequate' when power is supplied to customers with appropriate quality and system limits are observed. However, a power system is always exposed to unplanned and uncontrollable external events that are uncertain in their nature and timing.

In the timescales in which investment in network infrastructure takes place, the planner must deliver a network that can be operated safely, and must be mindful of future O + X. A relative lack of investment in network infrastructure would lead either to greater O (the operation of the ideal generation pattern is restricted which implies that other generation should run, which implies a higher cost, i.e. a direct economic impact) or greater X (some additional loss of supply takes place from time to time which has some generally indirect economic impact that may be particularly difficult to quantify). Clearly, in quantifying the anticipated future values of O and X for a given network infrastructure, account must be taken of the way in which the system is operated. This includes the use of any new control facilities such as special protection schemes, demand side management or active distribution.

2.2 Investment for asset management

In Britain, investment in network facilities to facilitate an electricity market, operation of the system and supply to consumers has typically been described as falling into one of two categories:

- load-related;
- non load-related.

The former refers to investments driven by changes to patterns of generation or demand. The latter refers to investment motivated by the management of assets, in particular the refurbishment or replacement of equipment that is still required for operation of the system but for which maintenance or repair has become uneconomic, either because the condition of the asset is such that it requires many interventions and is out of service for an excessive time (with an associated impact on operation of the system or reliability of supply), or because the unit cost of particular maintenance or repair interventions is excessive. In practice, a clean separation of the two categories of 'load-related' and 'non-load related' investment is not always possible: asset replacement is only required if generation and demand patterns dictate a continued need for an asset's functionality, and the replacement might not be like-for-like if generation and demand patterns have changed[1].

In addition to the opportunities afforded by new controls on the system, the installation of any communications infrastructure that makes the system more observable and controllable also promises to be useful in respect of monitoring of the condition of individual assets from which, over time, data can be gathered to inform the scheduling both of maintenance and of asset replacement.

2.3 The role of planning standards

The context of long-term system planning or system development can perhaps best be understood in relation to other timescales in which the processes of operational planning and system operation take place, and the respective uncertainties and disturbances. These are illustrated in Figure 1 below.

In investment planning timescales, the background conditions against which security criteria should be applied are known with much less certainty than in operational planning. (See Figure 1 where *all* the uncertainties towards the top of the figure affect system development planning). A practical response in some countries, e.g. as in chapters 2, 3 and 4 of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) in GB [4] or TPL-001 in the US [5], is for planning standards to specify, to some degree, the operational conditions to be considered as well as a particular set of secured events and supply quality. In addition, they may make specific and separate references to two criteria that would indicate a need for investment:

1. reliability of supply; and
2. the economics around restriction of 'market-led' generation outputs[2].

[1]The replacement of an asset by one of a higher rating might sometimes be the most economic way of meeting load-related needs in spite of the early asset write-off cost and maintenance or repair of the asset still being economic.

[2]In practice, different market arrangements and different system development conventions will lead to different ways of quantifying O in the I+O+X expression. For example, in a set of market arrangements based on locational marginal pricing, O might be the total paid in a market clearance by the demand side. If the complete supply and demand curves are both known, the total social welfare (sum of producer and consumer surpluses) might be quantified. Alternatively, the network investment planner might consider that the main influence of network capacity is on congestion surplus, i.e. the difference between what the demand side pays and the generation side receives in a market clearance though, in all cases, care should be taken not to double count the contribution of congestion surplus to meeting the cost of network infrastructure. Given that centralised electricity markets are generally cleared some time ahead of real time, e.g. day ahead, the costs of intra-day balancing adjustments may also be taken into account if they are significantly affected by network capacity and operational facilities. (See **[6]** for further discussion of different ways of quantifying benefits of investment, including non-financial benefits). In a decentralised market such as that in GB, the system development planner typically treats O as simply the cost of balancing services given some assumptions on generators' self-dispatch decisions. In all of these cases, while the immediate objective seems to be the minimisation of the total cost of electricity, if generators' revenues are not sufficient, generation capacity is likely to be closed and not replaced. This would have the consequence of an increase in X. Given the difficulty of quantifying X, a particular system reliability metric might be used and treated as a constraint. In a liberalised electricity supply industry in which the ownership and operation of generation is separate from that of the network, it may be difficult for a network operator or development planner to ensure that there is sufficient generation capacity and know where it is located relative to network capacity. Some countries either already have or are planning to introduce a generation capacity market to address that issue. This is likely to go some way to reducing the network developer's uncertainty about future generation capacity scenarios.

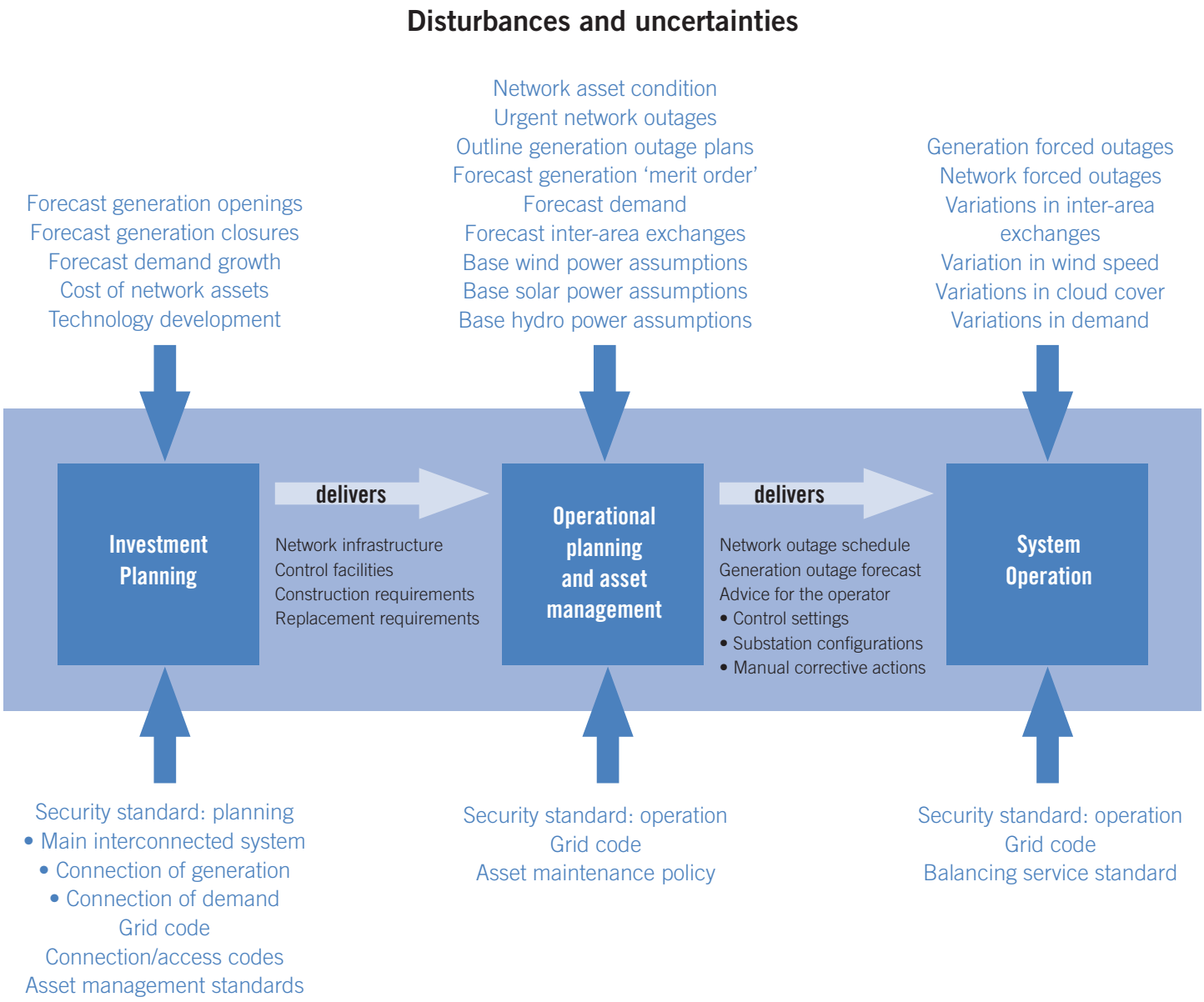


Figure 1: The context of investment planning as a facilitator of operation.

Planning standards have the aim of guiding the planner towards making approximately the right investments for management of I + O + X. In order to do so, they should be consistent with the security standards applied in operational timescales.

The consequences of specifying some particular future operational conditions against which the need for additional network capacity is to be assessed are:

- the number of individual analyses that need to be conducted by the planner is reduced;
- a certain 'margin' may be built into the design of the network, i.e. implied within the planning standard. This would be such that, when the system is finally operated, operation in compliance with the operating standard is possible albeit that it is not guaranteed always to avoid constraints on the operation of generation or loss of load though it should normally be possible to facilitate planned outages (such as for maintenance) of generation and network components in at least some combinations.

3. METHODS AND TOOLS CURRENTLY IN USE

Many of the methods and tools currently used by network planners in Britain and elsewhere have been developed specifically to address the criteria of the relevant planning standards. As a consequence, approaches differ between transmission and distribution planning. They are discussed in turn below.

3.1 Transmission planning

In 2011/12, CIGRE Working Group C1.24 on "Tools for Economically Optimal Transmission Development Plans" conducted a survey of 18 transmission utilities in 6 continents that revealed the following [6].

- Planners' primary focus has often been on the least cost investment necessary to achieve a certain level of reliability or security of supply though economic or market benefits, such as through facilitation of competition between generators, are becoming increasingly important.
- In respect of testing the adequacy of the planned or forecast system and identifying if there is a need for investment, in some countries the main focus is on peak demand conditions. Others study a few demand conditions but the majority use between 24 and 60 demand blocks.
- Only a few utilities use multiple generation expansion scenarios.
- The transmission network is modelled or represented in different ways. In some cases it is only at a regional or zonal level rather than nodal. Assessment of the adequacy of the network's capacity sometimes only uses 'DC load flow' or a transport model rather than an AC load flow.
- There is often a relatively unsophisticated model of the generation market based either on a simple 'merit order' or a single set of fuel prices.
- Equipment ratings considered are generally seasonal static ratings.
- Initially intact networks are often assumed in contingency analysis.

In Britain, the types of study undertaken by transmission investment planners depend on the precise objective. For applications by generators or demand side customers to connect or enhance a connection, load flows are carried out to check that there are no overloads under prescribed conditions and that voltages are within limits. Solved load flow cases are used as the starting points for assessment of fault levels with distribution networks modelled two further voltage levels down. If a generator is connecting in an electrically weak part of the system, transient stability assessment would also be carried out. Although it is currently proscribed, in future management of the risk of instability might be by means of a special protection scheme, and this should be represented accurately as a bespoke development of the system model. If the connection application concerns an HVDC converter station, a number of additional, specialist studies are necessary. (See Appendix B for a description in respect of Britain's new Western HVDC Link).

Analysis tools for such applications as load flow, short circuit analysis and stability assessment exist and are generally adequate at present. However, matching of data between different applications and different users is sometimes difficult and there can be significant problems with the implementation of models of new equipment, in particular wind farms and HVDC converters.

Clearly, connection studies require the provision of data by the applicant, as specified in the Grid Code [7]. In the case of generators, this includes the supply of dynamic models which might initially be provided as encrypted 'black boxes'. In such cases, it can be difficult to diagnose why responses are as they are though, equally, it might be argued that all that is required is verification that responses comply with Grid Code requirements and that, if they do not,

it is the applicant's responsibility to modify the generator's behaviour and submit a revised model.

Where analysis becomes more involved is in respect of power flows on the main interconnected transmission system (MITS). As already noted, it is the planner's responsibility to provide, where economically justified, such facilities as permit secure operation of the system. It should therefore be verified that secure operation can be achieved under credible operating conditions, and the cost of doing so quantified. In order to generate realistic market scenarios for the future, the network planner needs to make some assumptions and carry out forecasts of the future generation mix and the level and spatial and temporal distribution of demand. In a situation where the party responsible for planning and development of the network is different from that which operates the system and the real-time market, as is the case for the transmission system in Scotland, rules that limit one party's access to generation data make it difficult for the economic aspects of a proposed network development to be addressed in a coherent manner for the system as a whole.

The Western HVDC Link case study included in Appendix B describes the means by which a MITS study is typically carried out at present. Although commercial software is used for load flow and stability studies, e.g. PowerFactory **[8]**, it can be seen that there is significant reliance on spreadsheet based tools for economic appraisals that cover a large number of different operating conditions whereas, in other countries, commercial tools are often used, e.g. Plexos, Prophet, Uplan or PSR Net-plan **[6][9]**. However, certainly the British experience and probably also that elsewhere is that the study of multiple MITS scenarios, the costing of constraints and the interpretation of results is quite a specialised activity undertaken by only a few individual analysts.

3.2 Distribution planning

Aside from asset replacement, i.e. non load-related investment which is by far the biggest element of capital expenditure on British distribution networks at present, the main driver for new facilities on distribution networks for some decades has been growth of demand. This investment has primarily been governed in Britain by Engineering Recommendation P2, currently in its 6th edition (ER P2/6) **[10]**[3]. Hence, the tools and methods typically used by distribution planners for the 132kV and 33kV networks are driven mainly by the explicit requirements of the standard which concern thermal network capacity and, primarily, meeting of the peak demand in a group[4]. In addition, off-peak conditions should also be addressed under conditions in which there are two outages one of which has been 'arranged', i.e. planned such as for maintenance. Although P2/6 specifies a demand of two-thirds of the peak for such conditions, off-peak demands in the 'outage season' are often higher than that. Expansion of distribution network capacity might also be driven by connection of generation though expansion of the network to meet growth of demand might be offset or deferred by the contribution of generation to meeting that demand.

Largely because of the typical configuration of distribution networks in Britain (in most – but not all – DNO areas, operated radially at 33kV and below), network analyses such as power flows are, at present, typically only undertaken as part of investment planning studies of the 132kV and, from time to time, 33kV networks although it may also be carried out in cases where the network is operated in a meshed configuration even down to 11kV and circuit sharing needs to be checked. They are sometimes also carried out when the connection of generation is being studied.

In respect of lower voltage levels, simple extrapolations are commonly performed to estimate future 'after diversity maximum demand' (ADMD). In order to establish whether the terms of ER P2/6 can be complied with, this is compared on a simple algebraic basis with the network's capacity as represented by the static thermal ratings of series connections to each demand group[5], the capacity of the network to switch some part of the demand to other branches in the event of outages and the contribution to the meeting of demand that ER P2/6 says can be assumed from generation[6]. Such practice has largely proved adequate to date in managing risks to future demand and triggering timely reinforcement though, on occasions, more detailed, non -standard analysis might reveal a business case for additional facilities justified in respect of the customer interruptions (CI) or customer minutes lost (CML) incentives **[12]** These typically represent the installation of facilities for remote control of open points to enable faster restoration following fault outages and, to date, have mainly concerned interventions at the 11kV level.

[3]Normally, key industry standards, such as the National Electricity Transmission System Security and Quality of Standard (NETS SQSS) [4] or the Grid Code, both in Britain and elsewhere, are freely accessible; many documents maintained by the Energy Networks Association, not least ER P2/6 **[10]**, seem anomalous in being available only for a significant fee.

[4]The Distribution Code **[11]** requires that DNOs provide weather corrected ('average cold spell') peak demand data to transmission licensees. However, DNOs' current practice in respect of weather correction methodology is not published.

[5]'Cyclic' or 'emergency' circuit ratings are also mentioned by ER P2/6. However, in the former case it should be ascertained that off-peak loadings are such that cyclic ratings can be safely used without excessive heating of equipment. In the latter case, use of emergency ratings will accelerate ageing of the asset but the long-term effects are not easily quantified.

[6]ER P2/6 and its accompanying guidance set out some spreadsheet analysis that can be conducted to assess the expected contribution of generation. However, to the author's knowledge, most DNOs use the simple tables given in the main document.

The facilitation of generation is something that is receiving increasing attention from DNOs in Britain as they are encouraged to move away from what has been described as the practice of 'fit and forget' [13]. Such practice involves the DNO ensuring that operation of a generator is unrestricted regardless of the level of demand or the probability of generator output being at different levels. If this is not possible on the existing network, reinforcements are specified that would enable it to be so and all the associated network reinforcement costs are imposed on the connecting generator.

The above practice in respect of connection of generation is being increasingly superseded by consideration of 'active network management' (ANM) as an alternative to 'fit and forget' reinforcement [14]. ANM on a distribution network is analogous to special protection schemes or automatic generation control on transmission networks and involves an acceptance that, under some combinations of generation output and demand, network limits would be breached. These limits are monitored in real time and generation automatically curtailed until network limits are satisfied. While this can work well and represent an economic solution overall where the volume of curtailed energy and its cost to the generator plus that of the ANM scheme is small relative to the benefit of facilitated output, as volumes of curtailed energy increase, an appropriate network reinforcement might represent the most economical solution, especially when a number of different generators might be facilitated. However, to date, this has rarely been implemented, often because of the imposition of the total cost of the reinforcement on the first connecting generator regardless of whether the works might also facilitate the operation of later generators. (Where ANM schemes are implemented that interact with a number of different generators, common practice at present is that the last connecting generator is the first one to be curtailed, i.e. so-called 'last in, first off' (LIFO) [15] [16]).

Voltage performance and reactive power flows are rarely assessed by DNOs. Historically, as shown by the infrequency of customer complaints about voltage, this has not proved to be a problem but connection of generation to the distribution network can lead to issues. To avoid what DNOs judge to be problems associated with reactive power flows and increased network losses, DNOs have tended to require generators to operate in a unity power factor mode. Where connection of generation at lower voltages, e.g. PV at domestic or commercial properties, is judged to possibly lead to voltage rise issues under low demand, high generation conditions, connection of the generation might be prevented. However, some academic studies are now suggesting that voltage regulation by generators can help to avoid curtailment of active power or denial of access [17].

Final approval of connection of generation is conditional upon compliance with a number of particular standards that address the generator's technical characteristics:

- for generators with a current rating of 16A per phase or less, Engineering Recommendation G83/2 [18];
- for other generators, Engineering Recommendation G59/3 [19].

In the case of ER G59/3, verification of compliance may require particular studies to be performed. Checking of Grid Code compliance for the licence-exempt generators in the range 50-100MW may also require certain studies, most commonly in England and Wales.

4. KEY CHALLENGES

4.1 Overview of issues

It is been widely suggested, not least in the IET Power Network Joint Vision Technical Report [2], that a number of different control facilities can provide a more cost effective means of enhancing power network transfer capability than the provision of additional or more highly rated primary assets[7]. In addition, phase-shifting transformers or primary assets using HVDC can provide enhanced facilities by means of their extra controllability relative to AC overhead lines or cables. However, the extent to which they can be used or are encouraged in Britain depends on a number of factors. These include the following.

- The planning criteria in the Security and Quality of Supply Standard (SQSS) [4] currently prohibit the use of generator inter-trips (special protection schemes) to provide extra network capability in investment planning timescales.
- While the SQSS opens the possibility of use of dynamic or real-time ratings ("unacceptable overloading" is described as "overloading of any primary transmission equipment beyond its specified time-related capability"), ER P2/6 [10] says in respect of 'circuit capacity' only that "The appropriate cyclic ratings or, where they can be satisfactorily determined, the appropriate emergency ratings should be used for all Circuit equipment"; little guidance is given on the definition of 'emergency rating' or the implications of its repeated use.
- There are no tools currently in use by the National Electricity Transmission System Operator (NETSO) in Britain that permit the optimal or near-optimal setting of tap positions on phase-shifting transformers comparable to what is modelled by investment planners [20] [21].
- Neither conventions nor tools are currently in use by the GB transmission licensees to support decisions on the dispatch of power on an embedded HVDC link.
- There is no distribution equivalent to the operating criteria of the SQSS against which the adequacy of future operation can be tested and, in particular, provide the framework within which options of curtailing generation or re-scheduling storage or demand side management can be compared.
- Although it might be argued that the Electricity Safety, Quality and Continuity Regulations (ESQCR) [22] say all that is needed in respect of the requirement to manage voltages on a distribution network, ER P2/6 is nonetheless silent on voltage control and, arguably as a consequence, little modelling of voltage performance is carried out and reactive compensation or voltage regulation by distributed generators are rarely considered under conditions where voltages would otherwise be outside of limits.

As noted by the IET PNJV Technical Report, "changes such as solar photovoltaic (PV) farms and large scale adoption of domestic solar PV energy, electric/hybrid vehicles, replacement or supplementing of gas fired heating by electric heat pumps, community energy schemes, and the introduction of large scale wind generation have potentially profound impacts on networks and on the electricity system" [2]. Furthermore, "At the transmission level, traditional tasks such as system balancing and maintaining system stability will become increasingly complex while at the distribution level, managing the impacts of reverse power flows, fault levels, and voltage rise will become increasingly challenging. Solutions might include moving to automatic controls for new applications such as solar panels, electric vehicle charging, and for the adjustment of carrying capacity of transmission and distribution lines according to weather conditions (dynamic thermal rating). The implementation of such wide-scale automation needs to be handled with care to ensure stable operation of the power grid and avoid unexpected and serious outcomes as a whole"[2].

The rate of uptake of the technologies on the network user side (generation and demand) is uncertain; a number of the ways of managing increased variability and uncertainty of power flows are, as yet, unproven at scale but promise significant cost savings relative to established means of managing the system via increased holdings of generation reserve or increased capacity of primary network assets.

Investment planners need to take adequate account of the potential of demand side management, extended use of corrective actions, more active operation of distribution networks and greater use of facilities such as dynamic ratings and HVDC in ensuring future operability of the system at least cost.

In particular, it is suggested that:

a) the different uncertainties (such as shown in Figure 1)

[7] 'Primary' here is used in the sense of "Heavy current equipment that carries power currents at voltages from LV up to and including 400kV", in contrast to 'secondary' equipment which is "Ancillary equipment used to protect, control or maintain the Primary plant". (See Engineering Recommendation G85 [23]).

should be more explicitly modelled than they are at present and the associated risks quantified;

b) a greater range of potential operating conditions should be assessed by the network development planner than has normally been the case to date;

c) the power transfer capability of the network should be assessed using adequate models of facilities such as HVDC, dynamic ratings and corrective actions including responses actuated on the distribution networks by both generation and demand; and

d) because pre-fault operational 'headroom' on primary assets will be more fully exploited by a greater reliance on corrective actions, the facilitation of planned outages should be addressed explicitly.

Some particular challenges in respect of power network planning were outlined in [2]:

1. collating the wide range of data from multiple sources required to undertake effective power network planning[8];
2. effective sharing of and access to essential power network planning data;
3. uncertainty in future electrical demand technology including active and reactive demand profiles and responses under network emergency conditions;
4. the need for a range of planning models, standards and processes to address the emergence of active distribution networks;
5. cross-cutting issues in active distribution networks for transmission companies and distribution companies such as analytical models, operating regimes, commercial arrangements and service provision;
6. the need for new techniques and tools for network planning to address the new challenges;
7. cooperative approach to specifying, developing, validating and using new network planning techniques, tools and models; and
8. the need for overall coordination of strategic direction and supporting activities in transmission network and distribution network planning and the development of a whole system approach to this[9].

[8]This is described in [2] as being especially challenging at a time of rapid change in the wider power system in terms of new generation technology, demand technology and issues of scale, location and operating modes for both generation and demand.

[9]The establishment in 2014 of CIGRE Working Group C1.29 on "Planning criteria for transmission networks in the presence of active distribution systems" may be noted.

In addition to the need noted in [2] for greater attention to interactions between electricity transmission and distribution, there is also a need for electricity system planners to have a greater understanding of the whole energy system including the need for heat and its impact on both the gas and electricity systems and the impact of variability of renewable electricity generation on the supply of gas to combined cycle gas power plant.

The above set of challenges encompass three main themes:

1. management of and access to data;
2. the provision of methods and tools to allow the engineering questions to be addressed as conveniently as possible;
3. decision making frameworks.

To these could be added another theme:

4. provision of adequate skills among network planners and decision makers to manage data, use new tools and make decisions.

Each of the above themes is discussed in turn in section 5.

4.2 Analysis capability improvements recommended by CIGRE Working Groups

CIGRE Working Group C1.24 on "Tools for Economically Optimal Transmission Development Plans" [6] asked 18 transmission utilities in 6 continents what they saw as being the main improvements in analysis capability that should be made. The top three reported were:

1. **Robust and transparent input data**. Many respondents to the C1.24 survey aspire to improving their input data, while few currently regard their input data as robust and transparent. In some jurisdictions, the input data are set by an independent body following a consultative process. At the same time, there is growing awareness that there is significant unavoidable uncertainty regarding the future, and it is often the case that varying the inputs within a range of 'plausible' values can result in substantially different optimal outcomes. This is increasingly leading planners to consider a range of inputs, with the optimal solution being the one which minimises cost across a range of plausible futures.
2. **Complicated probabilistic analysis of variable generation, especially intermittent forms such as wind and solar**. The limited dataset of historical weather conditions (of sufficient quality and resolution), and the computational complexity of more sophisticated modelling are recognised challenges.
3. **More sophisticated modelling of electricity pricing on demand**. Electricity prices have risen significantly in some jurisdictions over recent years, and initiatives such as carbon pricing may affect the price of electricity into the future. The strong desire amongst some respondents to model the impact of price on peak demand and energy consumption may reflect a belief that these price increases have impacted on observed demand and/or are likely to have a substantial impact upon future demand.

Other areas identified as 'gaps' by WG C1.24 reflected desires to adopt:

- more sophisticated losses calculation and integration into studies;
- representative weather-correlated demand scenarios;
- Monte Carlo outage modelling;
- weighted demand diversity scenarios; and
- iterative transmission expansion modelling.

Another CIGRE Working Group, WG C6.19 on "Planning and Optimization Methods for Active Distribution Systems", published its report in August 2014 [24]. Based on survey responses from 34 DNOs from around the world (including one response from the UK, from Scottish Power Energy Networks), the WG noted some particular gaps in current practice, not least what is shown in Figure 2 below.

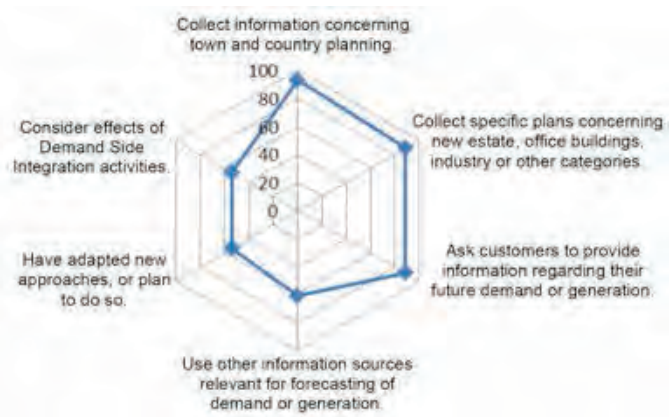


Figure 2: distribution network planning considerations revealed in a survey by CIGRE WG C6.19 [24].

The WG argued that "Distribution operation and planning stages can no longer be considered as separate tasks in the distribution business since the exploitation of existing assets with Advanced Automation and Control may be a valuable alternative to network expansion or reinforcement", and that planning of active distribution networks "asks for daily customers profile with a probabilistic representation to take account of uncertainties that characterize their behaviour". More specifically, it asked the following in respect of development of new planning tools.

1. **To what extent do operational aspects need to be modelled in planning?** The WG argued that time-series models are required but also advised that an assessment should be carried out around the trade-off between precision, in particular the granularity of time series models, and time required for both manual effort by engineers and computing.
2. **To what extend are sophisticated tools needed?** The WG argued that "future planning methods should be able to deal with real, large-scale cases but [it] is crucial to investigate the role of simplified approaches in providing acceptable solutions."
3. **How can uncertainties be dealt with?** The WG argued that "decision making under uncertain scenarios causes risks that should be explicitly dealt with by planning tools in order to allow objectivity and transparency".
4. **How can ICT infrastructure be cost-effectively planned for the long term?** The WG argued that the reliability of the communication infrastructure should be assessed as part of an evaluation of 'smart grids'.
5. **How should the huge amount of data in active distribution systems/ 'smart grids' be handled?** The WG highlighted the potential value of a hierarchical approach to collection and provision of data.
6. **How can the business case for active distribution systems be correctly assessed?** A major issue is recognised by the WG: DNOs' lack of experience with use of many of the approaches associated with active distribution. It suggests that a multi-objective optimisation may be useful in future in allowing different dimensions of a planning decision with heterogeneous units of measurement to be considered.

The WG also asserted that "reliability assessment methods … will be instrumental in evaluating and designing active distribution systems." However, it also notes that "assessments of active distribution system reliability are only as good as the data used to represent the various components' performance and reliability".

Finally, the WG highlighted a number of what it saw as potential barriers to the adoption of new tools that might aid the planning of active distribution systems (ADS):

1. "The lack of inclusion of DNO requirements specifications in the development of ADS planning tools.
2. The complexity of tools and burden of data requirements.
3. Significant training requirements could be needed by the DNO to be able to utilise the tool(s).
4. A framework for DNOs to analyse the costs and benefits associated with ADS planning tools, in comparison with traditional planning tools."

5. DISCUSSION OF KEY CHALLENGES

5.1 Management of and access to data

Perhaps the single biggest difference between power systems at present and the future power system envisaged in many reports such as [2] is the massive increase in the number of controls and actively participating actors on the system. If their combined effects are to be understood, demand met and use of low carbon generation facilitated, they must all be characterised in some way and, when ensuring adequate future operation (whether that be an hour ahead or 10 years ahead), modelled. The volume of data required and information to be extracted is daunting; moreover, it is very difficult at this stage of development of the 'future power system' to say how much detail, precision or coverage is required for any given level of confidence in achievement of future societal goals.

It may be argued that established practice in respect of management of and access to data is already inadequate. One of the main concerns highlighted by CIGRE WG C1.24 was exactly this [6] so it is not a uniquely British experience. In addition, CIGRE WG C4.601 published a "Review of the Current Status of Tools and Techniques for Risk-Based and Probabilistic Planning in Power Systems" in 2010 and recommended the greater use of probabilistic tools in both investment and operational planning but warned that "It is difficult to collect, prepare and maintain the data sets needed for such tools (i.e. reliability data, force outage rates etc.)" [25].

Some examples of the data challenges that already exist are as follows:

- generation openings and closures are consequences of decisions made by their owners based on commercially confidential information such that the generation 'background' appears highly uncertain to network investment planners[10];
- future operating patterns of generators are dependent on, in particular, relative fuel prices and these are highly uncertain;
- historic GB operating patterns are not made readily available to independent analysts **[26]**;
- utilities around the world are finding increasing inaccuracy in their long-term demand forecasts **[27]**;
- the extent of 'voluntary' demand reduction by consumers (mainly large consumers to reduce demand side use of system charges) is only approximately understood;
- the effect of generation embedded within the distribution system in meeting demand and reducing transfers from the transmission system is not well characterised;
- improved power factors for demand are being observed but the reasons for it and its dependency on time of day or day of the year are not well understood;
- the voltage dependency of load is not as it has historically been assumed to be;
- investment planners typically use only very crude representations of the availability of wind power or solar power, or else use operational experience from a single year;
- the detailed models of wind farms provided by connection applicants tend to be unsuitable for whole system stability studies while simpler, generic models of single turbines cannot be assumed to have been tested in respect of their use in representation of wind farms;
- accurate models of HVDC converters typically only become available to the network planner or operator after the equipment has been commissioned, if at all;
- reasonably faithful models of the GB power system's dynamic characteristics are not available to engineers or researchers outside of the transmission licensees meaning that independent studies of future operational challenges and potential solutions lack the credibility that they might have had **[26]**;

[10]It is possible that the implementation of a capacity mechanism will reduce this uncertainty somewhat.

- while some new facilities allow the CML and CI improvements associated with different network developments to be estimated [28][29], input data on customer numbers at each secondary and the return to service times associated with different actions are scant.

A number of the above issues, particularly around forecasting of weather and demand and around modelling of dynamic system behaviour, are discussed in companion papers to the present one. However, it may be noted here that some actions are already under way addressing some of the above, in particular under the auspices of a number of 'Low Carbon Networks Fund' (LCNF) projects[11]:

- monitoring of power flows by newly installed equipment at secondary substations should allow more accurate characterisation of demands at low voltage;
- unrepresentative outliers in recorded power flow data can be readily identified using simple spreadsheet tools and, as a consequence, better forecasts produced;
- new understanding of the changing nature of demand within all three main sectors – domestic, commercial and industrial – is largely facilitated by improved network monitoring and collection of data and can enable more accurate ADMD factors;
- different methods and tools have been proposed to aid the creation of distribution power flow models;
- the voltage dependency of load is being investigated;
- provision of weather monitoring and spatial interpolation methods can allow the application of real-time ratings[12]; when integrated with recent time series of power flows, dynamic ratings can also be estimated; when an adequate database of historic weather patterns has been developed, they can be applied probabilistically in investment planning [30]; new work is addressing short-term forecasting of real-time ratings.

Among the future data issues not already mentioned is the reliability performance of new system controls and offshore assets [31].

5.2 New methods in support of planning of power networks

It is often assumed that, to plan a future power network, the power network must be modelled in full. However, it was already noted in section 3.2 that distribution networks in Britain are rarely modelled at 11kV and below at present except as simple 'after diversity maximum demand' (ADMD) figures that are compared with nominal feeder ratings. Meanwhile, although the transmission network does not necessarily need to be modelled in full for generation or demand connection studies (the immediate impacts may be expected to be observed in the vicinity of the point of connection so the wider system need not always be modelled in every detail), it would seem to be necessary when planning the MITS. In particular, the exploitation of the full pre-fault capacity of primary assets by means of more extensive corrective actions would seem to require the individual assets and actions to be modelled accurately. This may be expected to be equally true of actively managed distribution networks. However, if a network is to be modelled in every detail, every detail should be correct. When assembling representations of a power system for many years into the future under many scenarios, that entails a very large administrative burden. Moreover, there are so many uncertainties, it is argued in [32] that effort is perhaps better invested in modelling the system approximately for a sufficiently large number of cases than in modelling it precisely for a few. The consequence in the latter case would be that study conclusions may be very precise but also very precisely wrong.

Two large, European collaborative projects concerned with planning of the European transmission system have initially taken the view that as much detail as possible should be modelled [33][34]. If the system being modelled is very large, this presents considerable computational challenges. Similar issues have been faced in a research study in the US where parallelisation of the problem and the use of high performance computing have been brought to bear [35].

An alternative to brute force that can help inform stakeholders of the general need for transmission capacity has been used in a number of studies, e.g. [36][37][38] and the economic appraisal of the case for the Western HVDC Link discussed in Appendix B. An aggressive simplification of the network – e.g. down to each node in a model of Europe being a whole country – allowed each hour of a year to be modelled sequentially and the effects of uncertainties to be tested in [36] or the total cost of generation and additional network capacity to be minimised [37].

[11]See https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund/second-tier-projects for reports from a large number of projects.

[12]A range of technologies are now available for real-time rating of overhead lines, each of which has different characteristics in terms of cost, outage requirements, spatial coverage and accuracy.

Such approaches could prove invaluable when studying GB's interactions with the rest of Europe or within GB when a very large number of scenarios need to be studied. However,

- net transfer capabilities (NTCs) between modelled regions can only ever be representative of actual limits;
- within region network constraints are not modelled except insofar as an NTC is reduced;
- where a minimisation of the total cost of the network plus generation is sought, appropriate reinforcement costs must be used but are extremely difficult to determine.

One possible way of overcoming these limitations and reaching a suitable compromise between modelling accuracy and the ability to assess the effects of many uncertainties is outlined in Appendix C.

In respect of distribution, commercial tools used by DNOs such as PowerFactory and IPSA are periodically enhanced. For example, IPSA has recently had facilities added to calculate real-time ratings of transformers and to estimate CML and CI for a given initial network configuration [28]. (The particular innovation in IPSA's version of that feature is that it models an operator's reasoning on the quickest way of restoring any part of the disconnected demand for any single fault that occurs and hence gives a realistic estimate of CML [29]). However, DNOs in Britain currently have little experience and few well established methods to assist them in evaluating the following:

- the network 'headroom' that might be made available by use of real-time thermal ratings and the provision of confidence to operators that real-time ratings can be used safely.
- the extent to which higher power flows might give rise to voltage problems and the cost-effectiveness of reactive compensation or voltage regulation by generators.
- the value of storage compared with alternatives. (Storage of electrical energy remains very expensive and is currently only a realistic option where the main alternative – extra network capacity that would allow temporary surpluses or deficits of power to be shared with other locations – is also very expensive or where batteries are already installed for other purposes, e.g. electric vehicles, and the cost of acceleration of ageing can be compensated adequately).
- commercial generation services such as payment for availability or compensation for denial of the generator's full access to the network.
- the effectiveness and cost of demand side measures such as re-scheduling of demand. (This would include the use of heat storage in premises using electric heating which would have the effect of providing flexibility in the timing of demand).

As a consequence it could be argued that there is currently considerable room for improvement in the planning of distribution networks. Some case studies presented by CIGRE WG C6.19 suggest some potentially useful new approaches to aspects of the distribution network planning problem [24] and some ideas are beginning to emerge from various LCNF projects in Britain. At the time of writing, a major study has been commissioned by Workstream 7 of the Smart Grid Forum in Britain to evaluate the engineering performance of various 'smart grid' interventions and may deliver some methodological innovations that will be useful to DNOs in planning the future network.

5.3 The provision of convenient new tools

At one level, the network planner already has most of the tools they might need or they can buy them from commercial providers: power flow; short circuit analysis; transient stability assessment; reliability assessment, at least of quite small networks; and specialist studies such as harmonic analysis or motor start-up or electro-magnetic transient studies. They also have access to spreadsheet software that can be configured to conduct any number of different analyses for the purpose of, for example, forecasting or economic appraisal. However, having access to these tools does not necessarily mean that studies can easily be carried out:

- models must be created and maintained using adequate data;
- it must be ensured that analyses conducted using different software and the conclusions reached are accurate and consistent.

General data issues have been discussed in section 5.1. Particular issues associated with data for power system analysis were discussed as long ago as 2002 [39]. There, a major highlighted challenge was that arising from the potential need to maintain data describing common assets in multiple databases in multiple formats.

It has been suggested by CIGRE WG C1.24 that 'complicated' modelling of wind and solar power is required, by which it might be supposed is meant adequate representation of the spatial and temporal variability of these resources. It also suggested a need for Monte Carlo outage modelling [6]. CIGRE WG C4.601 argued that the growth in uncertainty in power system operation means that the planner must use probabilistic tools capable of analysing a very large number of scenarios [25]. Researchers involved in the GARPUR project [40] that started in 2014 and is due to finish in 2017 have highlighted, among others, a number of questions that a planner must answer under the following headings:

1. Generation of credible operational conditions against which the system developer should assess the sufficiency of network capacity.
   - What are the simple but accurate methods that can be used to synthesise patterns of availability of wind, solar and hydro power in different locations through a year of operation? To what extent should they be developed to show inter-annual variability?
   - What are the credible patterns of planned outages of generation and network components that can arise?
   - What is the spinning reserve that is likely to be carried and how would this reserve be spatially distributed?
   - Are the realistic constraints on operation of generation in real-time such as ramp rates, minimum stable generation and minimum on and off times significant enough relative to the uncertainties regarding the background conditions to require the use of sequential simulation in modelling the dispatch of generation on the system? What is the difference between the 'ideal' plan with and without these constraints?
2. How should system responses to disturbances be simulated by the system developer?
   - A system developer can assume that the control facilities available to the system operator are optimally utilised. How should this be modelled in system development studies? Should optimal utilisation always be assumed? If not, how should errors or failures be modelled?
   - What disturbances should be modelled for each initial condition?
   - What are the practical steps to be taken to model in software the following equipment options that are being increasingly widely considered by system developers: HVDC, special protection schemes (SPS), automatic generation control (AGC), phase shifting transformers (PST), flexible AC transmission systems (FACTS), demand side management (DSM), real-time thermal ratings (RTTR) or dynamic thermal ratings (DTR) among others?
3. What are the methods that can be used to make sense of the results of system simulations? (Can some filtering approaches be used to identify representative snapshots that can be modelled in detail?)
   - How many different cases are required to be studied and what weighting should be given to each?

As well as access to data, what is really at issue for the planner of a future power system is the *convenience* with which new challenges can be met. In other words, time and effort could be invested in building models in whatever software has the necessary functionality. However, if many cases should be set up and studied in order to have sufficient confidence in the conclusions, would it not be both more efficient and a more reliable process if integrated tools could be used that:

- had fully validated models and power system behaviours already built in; and
- minimised repetition and manual interventions?

A number of tools are available on the market that include many – but, perhaps crucially, not all – of the features that a transmission planner, in particular, would want. For example, Plexos includes unit commitment and economic dispatch solvers and a DC power flow [41]. However, it does not include an AC power flow or stability analysis. Assess, one of the tools discussed as a case study in the Appendix, includes a security-constrained AC optimal power flow (OPF), a quasi steady-state AC power flow and a stability assessment facility and can be integrated with a statistical tool for storage and analysis of results [42]. However, it relies entirely on the user to define rules for the creation of study cases and to make sense of the results, the cost model used in the OPF might not be suitable for the particular market arrangements, and it does not have a unit commitment function.

A tool designed to enable probabilistic system development planning in England and Wales was available within National Grid in the 1990s: ESCORT. Although it was incapable of modelling voltage performance and reactive power directly (once quantified, voltage constraints could be modelled as limits on inter-area power transfers), it *was* capable of [43]:

- sampling generation unavailability;

- dispatching available generation in an economic manner;
- modelling multiple demand cases;
- testing security constraints and costing generator dispatches to satisfy them;
- optimising phase shifting transformer settings;
- modelling seasonal ratings; and
- modelling special protection schemes (system to generator inter-trips).

The last of the above and another capability that it was designed to have (but, to the author's knowledge, was never used except in software testing), that of synthesising credible planned outage patterns, were extremely unusual at the time; the latter remains rare even now. However, the interface was based on multiple text files and was extremely unwieldy. Inevitably for so powerful a tool (Assess and Plexos and, according to many users, even Digsilent PowerFactory have the same issues), it was highly complex and difficult and, as a consequence, was suitable for use only by specialists. That gives rise to issues that are discussed in section 5.5. Largely as a result of the inconvenience of the interface and a decline in the number of individuals capable of using it, ESCORT fell into disuse in the early 2000s.

5.4 Decision making frameworks

The use either of very powerful network model creation and analysis tools or iterative procedures that make use of heavy simplification promise to allow very many scenarios to be studied and, hence, the impacts of uncertainties to be understood. However, the data generated still must be interpreted in order to inform crisp investment decisions.

The purpose of a network is enable demand to be met reliably and to facilitate operation of generation. Priorities in respect of the latter are given to effective competition or to low carbon generation or, if financial mechanisms are in place that allow low carbon generation to compete strongly, both. In principle and as discussed in section 2, reliability or 'security' of supply and facilitation of generation can be treated on a common basis. However, in practice, it is generally difficult to reach a consensus on the 'value of lost load' that applies under all circumstances; as a result, while the benefits of facilitating generation are measured in units of pounds, euros and so on, reliability of supply is typically measured is units of hours per year or MWh per year. Many transmission utilities therefore address two drivers for investment separately: economics and facilitation of generation (associated mainly with exports of cheap power from an area); and reliability of supply (associated with imports of power into an area) [44] [45].

The GARPUR project [40] has articulated the following questions in respect of improved methods for transmission system planning under uncertainty:

1. Risks: what are the thresholds of acceptability in respect of probability and magnitude of adverse outcomes?

a) Should thresholds be treated for all parts of the system on the basis of a single, common metric, or might there be different metrics in respect of reliability of supply to consumers and restriction of operation of generation?

b) Is it useful to think of 'import risk' in respect of the former and 'export risk' for the latter, with different acceptability thresholds? (Can particular areas of the system be identified that are normally subject only to 'import risks' or 'export risks'?)

2. Framing of a system development approach for planners working in utilities: will it be sufficient for planners to be told, only in general terms, the kinds of uncertainties and variations to model and the risk metric to use, or should something more prescriptive be set down? Or, should it be spelled out that certain values of risk would require action to reduce the risk?

In the REALISEGRID project [33], a number of dimensions of benefit in network investment decision making were cited along with the proposal that each has a particular weighting and a single total benefit metric quantified for each investment proposal, including that of doing nothing. The benefit dimensions included the following:

- reliability increase;
- congestion reduction;
- market competitiveness increase;
- system losses reduction;
- better utilisation of renewable generation;
- emission savings;
- external costs reduction;
- fossil fuel costs reduction; and
- capital deferral.

Although it is possible to estimate the magnitude of benefits for one particular future, it is difficult to make a decision given the range of different possible futures and the benefits that might be expected to arise under each of them for each of the proposed investments.

The SQSS in Britain does provide some guidance on how to treat many of the uncertainties towards the top right of Figure 1 [4]; however, it is silent on those at the top left: generation openings; generation closures; demand growth; cost of network assets; and technology development. A particular difficulty arises when primary assets do seem to be the best option but they have such a long lead time that a commitment should be made to them before there can be complete confidence, given various long-term uncertainties, that they really are the best option. In this context, flexible, operational measures such as corrective actions or dynamic ratings might be seen as buying time until there can be greater certainty. This is what is argued in the LCNF "Flexible Networks" distribution project [46]; however, it might equally well be argued that such measures should be part of the 'business as usual' toolkit providing 'baseline' network capacity. If power flows continue to increase, the extra capacity they provide will be exhausted and primary assets will still be required albeit their deferment would seem to have the benefit of reducing their cost in net present value terms. On the other hand, excessive delay might mean losing planning permission or wayleaves that are already available. A particularly important consideration in respect of transmission planning is that delay can mean that the cost of outages to enable the construction work is prohibitively high.

The risks associated with investment planning include primary assets being stranded but also include a dependency on new technologies that do not perform as expected, or an increase of the probability of a high impact event such as a system blackout from a very low value to a higher but still quite small value. The latter may well be the case with greater dependency on corrective actions, especially time critical actions such as for the management of system stability. Risks associated with high impact events are particularly hard to evaluate, especially if the analysis, such as is the case in the nuclear industry, depends on estimation of very small probabilities.

It is suggested in [47] that, in the context of capital investments in assets with a lifetime of many years, "choosing the option that has the smallest maximum regret is preferable to minimising an expected value mainly because the decision process is not repeatable. It is equivalent to putting a cap on just how bad things could get." A comparable philosophy underpins the planning of system defence measures: it cannot be guaranteed that the system will not be subject to major disturbances; however, when such disturbances happen, measures will be available that will not prevent an impact but will limit its extent or scale. Such measures are likely to be of increasing importance on the future, 'smarter' power system and investment planners will be responsible for ensuring that they are put in place [1].

National Grid in Britain now makes use of the min-max (or least) regret paradigm. (See, for example, chapter 4 of the Electricity Ten Year Statement (ETYS) [48]). Another way of framing the decision paradigm, comparable to min-max regret, is outlined in [49] (cost of adapting from one situation to another). However, it is also suggested in [47] that "in a decision problem in which there are a great many possible scenarios, [a min-max regret approach] risks placing too much weight on single outlying outcomes. An alternative then is to minimise the sum of the worst say 5% outcomes, i.e. to minimise the value at risk to the 95% level".

Although National Grid includes a public presentation of min-max regret in the ETYS, the regulator, Ofgem, might argue that a network licensee could use any approach it likes to inform a decision in respect of 'anticipatory investment' for which there might be a significant risk of stranded assets but also a higher rate of return should the assets have proved beneficial.

5.5 Provision of adequate skills

Every actor in the electricity supply industry (ESI) is under understandable pressure to reduce costs. One of the most significant dimensions of cost is that of the personnel required by an organisation. It should therefore come as no surprise that companies in the ESI seek to minimise the 'headcount' provided the company can adequately deliver its service. However, in some respects, not least for DNOs, the nature of the service is changing and becoming more demanding. A particular example of this is the provision of generation connections: the number of applications has significantly increased in the last few years and the methods and personnel available to service them have arguably not kept pace.

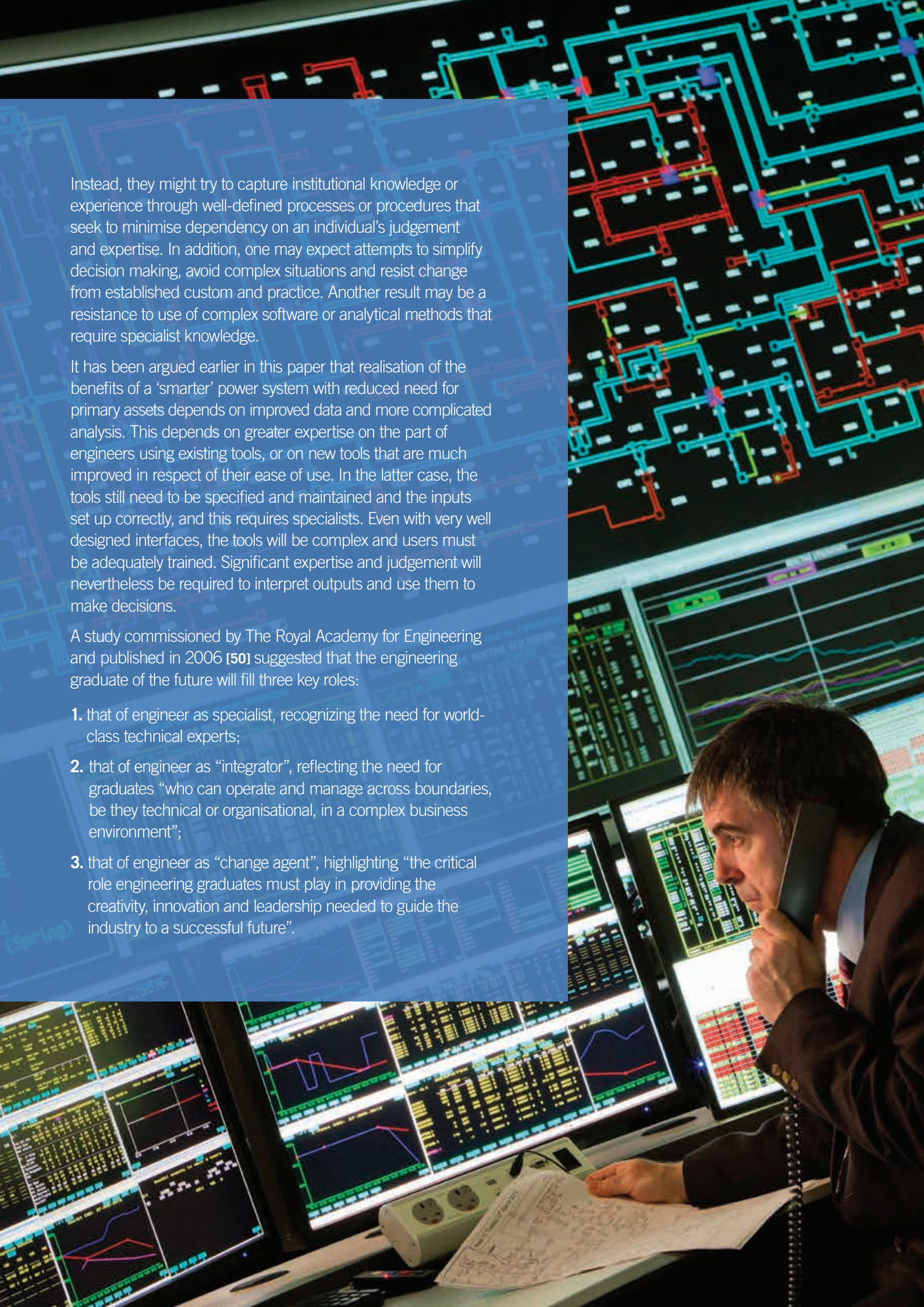
Companies in the ESI may be particularly expected to attempt to reduce the cost of the most expensive employees. This includes managers and technical specialists. (Managers might be regarded as 'management' or 'leadership' specialists). 'Specialists' are, by definition, special: relatively few people have their skills or knowledge. If those skills or knowledge are important, these specialists might be able to command a premium in the labour market. Hence, it would seem logical that companies try to keep dependency on specialists to a minimum.

Instead, they might try to capture institutional knowledge or experience through well-defined processes or procedures that seek to minimise dependency on an individual's judgement and expertise. In addition, one may expect attempts to simplify decision making, avoid complex situations and resist change from established custom and practice. Another result may be a resistance to use of complex software or analytical methods that require specialist knowledge.

It has been argued earlier in this paper that realisation of the benefits of a 'smarter' power system with reduced need for primary assets depends on improved data and more complicated analysis. This depends on greater expertise on the part of engineers using existing tools, or on new tools that are much improved in respect of their ease of use. In the latter case, the tools still need to be specified and maintained and the inputs set up correctly, and this requires specialists. Even with very well designed interfaces, the tools will be complex and users must be adequately trained. Significant expertise and judgement will nevertheless be required to interpret outputs and use them to make decisions.

A study commissioned by The Royal Academy for Engineering and published in 2006 **[50]** suggested that the engineering graduate of the future will fill three key roles:

1. that of engineer as specialist, recognizing the need for world-class technical experts;
2. that of engineer as "integrator", reflecting the need for graduates "who can operate and manage across boundaries, be they technical or organisational, in a complex business environment";
3. that of engineer as "change agent", highlighting "the critical role engineering graduates must play in providing the creativity, innovation and leadership needed to guide the industry to a successful future".



As the title of the IET PNJV group's report implies –"Electricity Networks: Handling a Shock to the System" – the future power system will represent a significant change from what has come before. If the transition is to be managed, high calibre people will be required in all three of the above roles.

The importance of power systems knowledge should not be underestimated. The future power system will undoubtedly behave in subtly and sometimes dramatically different ways from the present day system and not all of it will be benign. Anyone responsible for 'keeping the lights on' will be unable to rely simply on referring back to existing procedures and what they have seen before because it will not all have been seen before; they will have to be capable of going back to first principles in respect of power systems engineering to reason through what has happened and what needs to happen next. As an example of a trend that has already started, the installation of series compensation and the need to manage risks of sub-synchronous resonance has required network planners to understand issues that have never needed to be explored in such depth in Britain before. Furthermore, although it is perfectly possible for specialist studies to be contracted out, the responsibility for the final investment decision rests with the transmission owners and for operation of the equipment with the NETSO. Network licensee staff should be capable, if not always of constructing models of new facilities, at least of verifying that models provided by others are fit for purpose. They should also be capable of writing equipment specifications such that what is required for the GB system can be delivered and contract costs adequately managed in the best interests of GB consumers who are expected to meet the final bill.

The benefits of 'smarter' power systems with a reduced need for primary assets will not come for free; utility managers and regulators that make judgements on reasonably incurred costs need to recognise the cost not only of the physical facilities to provide new system controls and the contracts with different system actors that provide services but also the cost of new tools and the human resource cost of highly skilled engineers capable of using tools and making prudent recommendations on future network investment.

A related issue concerns the provision of educational foundations and ideas upon which new methods and tools and understanding of new technology can be built. Universities play a very important part in this, though consultancies and software providers also have a role in respect of specialist studies and development and maintenance of tools.

Universities' ability to provide both the educational underpinnings to advanced knowledge and new insights depends on development and retention of expertise and knowledge within the university. Research council funding is increasingly uncertain in this regard and, to a large extent, focuses on training of postgraduate students and not building and maintenance of research capacity. The research councils generally assume that other funding sources will be used for that. However, the network utilities have historically shown a reluctance to fund research except where an allowance of customers' money has been made available by the regulator. The rules are being changed in respect of allowances that drive specific 'innovation projects' that are expected to show an immediate cost-benefit [51]. No value is seemingly attached to the retention of skills and knowledge within universities or to research carried out to inform the industry on *emerging* risks and opportunities in the planning and operation of power systems and from which specific 'innovations' might at some point spring.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 Recommendations of the IET Power Networks Joint Vision panel

In its Technical Report, the IET's Power Networks Joint Vision group recommended a number of actions in respect of planning of the future power system [2]. They are repeated here for convenience.

1. development of a specification and governance approach for a GB network planning data repository;
2. review of the long term planning data submission ('week-24 data') from DNOs to the NETSO to make it more efficient and effective;
3. commissioning of a study on emerging and future demand types;
4. development of the scenario planning based approach now adopted by the NETSO in the ETYS to enhance robustness and track trends and observations in the sector;
5. development of planning models, standards and processes for the treatment of active distribution networks;
6. establishment of a transmission and distribution network company working group on active distribution networks to tackle the cross-cutting issues;

7. development of requirements and specifications for techniques and tools for network planning to address the new challenges and provide the launch pad for diverse stakeholders to contribute;
8. establishment of a steering group to lead, oversee and approve tools and models for network planning in GB.

6.2 Conclusions and recommendations from the current review

This paper has discussed current practices internationally and in Britain in power network investment planning and the need for improvements to data, methods and tools to enable planning of a future power system. The future system should accommodate greatly increased generation of power from low carbon sources in such a way that the network cost is minimised while delivering desired levels of reliability of supply, primarily by means of minimising the requirement for new primary network assets and making greater use of network controls, in particular to correct outcomes of disturbances. Based on the discussion of needs and current practice and capabilities presented earlier in this paper, a number of conclusions are reached and recommendations made under four main headings:

1. management of and access to data;
2. the provision of methods and tools to allow the engineering questions to be addressed as conveniently as possible;
3. decision making frameworks;
4. provision of adequate skills among network planners and decision makers to manage data, use new tools and make decisions.

The recommendations presented below are judged to represent actions that are both important and achievable. However, it is recognised that, in respect of many of them, detailed further work will be required to define the steps more precisely and that different aspects may require action at a regulatory level not only within network utilities or on the part of their contractors such as software providers, consultancies and research institutions. Examples of regulatory interventions that might be required include revision of standards or the development of memoranda of understanding that permit sharing of basic data, e.g. between retailers and network utilities, while minimising the exploitation of rent opportunities by owners of data or invasion of privacy.

There is likely to be considerable value in collaboration between different utilities, consultants and research leaders to address the challenges but actors in Britain should be aware that many of the most mature insights and innovations are taking place outside Britain. International collaboration should be pursued, e.g. through CIGRE Working Groups and European research projects, and utilities in Britain should be prepared to commit sufficient resources if the benefits of learning from others are to be maximised.

6.2.1 Management of and access to data

Conclusions

- Although current methods for management of and access to key data for the support of planning of the future power system have been largely though not entirely adequate to date, they are inadequate for dealing with new challenges such as greater penetration of renewable energy, the extended use of corrective actions and the increased utilisation of, for example, real-time thermal ratings, HVDC, phase shifting transformers and scheduling of flexible demand. The expected huge increase in the number of individual active participants in the power system also presents challenges in terms of access to and management of data.
- Even without the new challenges, it is possible that significant improvements could be made in respect of the efficiency and accuracy of data management and exchanges between different units within a company and between different companies including in respect of assumptions about generation patterns and system operation.

Recommendations

- Time series, at suitable spatial and temporal granularity, should be made available to investment planners in respect of power available from wind and solar generation in such a way as to adequately represent temporal and spatial correlations. Distribution planners should have access to suitable demand time series and patterns of operation of embedded generation. Transmission planners already have access to time series of net demand but should also have access to data describing the behaviour of embedded generation.

- Of particular importance for transmission planners is access to adequate models of generators and HVDC converters including correct control system parameters; this access should be improved and the models made available within standard analysis packages.
- Network utilities at both transmission and distribution levels should invest more in the collection of asset reliability data and its processing not only for asset management but also for system reliability assessments. This is particularly important for new types of asset and for equipment involved in facilitating corrective actions.
- In future, distribution asset data should be maintained in such a way as to make the construction of system models more convenient. The business case for conversion of legacy data sources into more efficiently manageable forms should be explored.
- The characteristics of loads with respect to dependency on voltage and system frequency should be assessed and made available to network planners and operators.
- The main parameters of the GB transmission network are already available to independent researchers. The main parameters of distribution should be equally easily accessible. The main parameters of transmission connected generators and HVDC converters should also be made available to independent researchers but, in order that sensitivities around commercial confidentiality are respected, cost data withheld except in respect of outturns of final outputs and accepted bids and offers from the GB balancing mechanism at a unit level and other outturn data necessary to inform ancillary service markets.

6.2.2 The provision of new methods and tools

Conclusions

- Analysis tools for such applications as load flow, short circuit analysis and stability assessment exist and are generally adequate. However, matching of data between different applications and different users is sometimes difficult and there can be significant problems with the implementation of models of new equipment, in particular wind farms and HVDC converters.
- Methods and tools used in distribution planning are generally unsophisticated and have changed little in many years. Established methods are not yet evident in respect of voltage and reactive power and evaluation of curtailment of generation. However, a number of Low Carbon Networks Fund (LCNF) projects promise useful progress.
- Useful new methods and tools applicable at transmission levels have been developed in Britain and elsewhere that have many of the features that seem to be required to facilitate planning of the future power system against an uncertain background. However, they are either not yet sufficiently mature (in particular in respect of user interfaces and access to data) or the capability to use them has not been maintained.
- New and emerging power system challenges require development of new methods and tools.

Recommendations in respect of new methods in network investment planning

- A better understanding of long-term influences on growth (or otherwise) of demand should be gained along with interactions with different energy systems such as those for gas, heat and transport.
- Work should be undertaken to articulate an appropriate trade-off between model simplification, precision and the burden of managing large volumes of data and computational complexity.
- Improved methods for identifying bad data in respect of historic distribution network performance and using the cleaned data to inform planning should be further developed and then adopted.
- In addition to what is emerging from some LCNF projects, further work should address ways of dealing, with confidence, with lack of observability on distribution networks and allowing planners to make reasonable assumptions.
- Understandable and effective methods should be developed for planners to evaluate real-time thermal ratings and flexible demand.
- Understandable and effective methods should be developed for distribution planners to evaluate storage, curtailment of generation and voltage issues and potential solutions.

Recommendations in respect of new tools for network investment planners

- Different data sources should be better integrated and maintained and new tools developed for the efficient formation of models and operational scenarios to allow the operational implications of planning decisions to be evaluated, including in respect of automated responses, real-time ratings, re-scheduling of flexible demand, HVDC and phase shifting transformers.

- Tools should be developed to allow the more efficient processing of applications by small generators to connect to the distribution network.
- Effort should be invested in development of Monte Carlo tools capable of dealing, in a convenient way, with variations in generation and demand and planned outages as well as unplanned disturbances.
- Aids to the interpretation of power system analysis results should be developed and made available to investment planners.

6.2.3 Decision making frameworks

Conclusions

- Progress has been made in recent years in respect of evaluation of options for transmission development under uncertainty and new technologies are being deployed. However, some approaches, such as system to generator intertrips, are precluded in investment planning timescales, guidance is scant on the management of 'complexity', the facilitation of planned outages is not always clearly addressed in respect of the main interconnected system and methods for assessment of risk of major interruptions have not yet been widely established.
- Approaches at a distribution level for decision making under uncertainty and the evaluation of options for active network management are quite immature.

Recommendations

- Access to current industry standards should be made easier by applying the example of publication of the Security and Quality of Supply Standard (SQSS) and Grid Code on the web also to distribution standards including ER P2/6, ER G59/3 and ER G83/2 thus enabling contributions to discussion of appropriate revision of standards to better facilitate the future power system in customers' best interests.
- A framework should be developed that allows a more explicit quantification and use of 'risk', i.e. the impact of different uncertainties including reliability of service to network users, as an informer of investment planning.
- Acceptable levels of risk should be defined and, where necessary, standards revised to drive action to satisfy those levels.
- Different methods should be evaluated for using risk to make decisions.

6.2.4 Provision of adequate skills and expertise

Conclusions

- There has been understandable pressure on network utilities to reduce 'headcount' and dependency on specialists.
- There is increased pressure on DNOs in respect of processing of generation connection applications.
- The development and retention of power systems expertise and specialists in the methods and tools associated with planning the future power system are crucial to realising the benefits of new approaches to operating the system and new technologies employed on it.

Recommendations

- Investment planners and their superiors should develop their understanding of the nature of 'risk' and its analysis. This should include an understanding of average outcomes, e.g. in respect of reliability of supply over a period of time, and rare events that may cause major loss of supply, and will depend on some familiarity with basic statistics.
- A sufficient pool of power systems experts should be maintained within a network utility capable of assessing new technologies, verifying the appropriateness of models, writing equipment specifications and evaluating system behaviours not seen before.
- An understanding of methods for decision making under uncertainty should be developed.
- Utilities, not only consultancies, manufacturers and research institutes, should commit to the development of staff such that they can understand and make full use of new analysis methods and tools.
- A commitment should be made to the retention of skills and knowledge within universities in order that education of future power engineers can be achieved and research carried out to inform the industry on emerging risks and opportunities in the planning and operation of power systems. Funding of universities by industry should not be entirely dependent on specific 'innovation projects' but should contribute to the underpinning of capability and the ability to inform regarding future opportunities and threats.

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APPENDICES

A. Case studies – Transmission Planning tools

A.1 Advanced transmission planning tools in England and Wales

To help show what is possible with existing software and to illustrate some of the issues associated with use of advanced power system analysis tools, the following case study is presented.

In the late 1990s, National Grid Company (NGC) was becoming increasingly aware of uncertainty of the generation background against which the Main Interconnected Transmission System (MITS) in England and Wales was being planned. Since industry liberalisation and separation of ownership of generation from that of transmission, exactly which power stations would be open and which closed was outside of the transmission planner's control; while new connections had to be facilitated by the transmission licensee, there would generally be at least 2 years notice but closure or mothballing of generation could take place with no notice. Given that lead times for major transmission reinforcements would often be well in excess of 2 years, either strategic MITS reinforcements would be carried out too late with an ensuing risk of excessive constraint costs or risks to security of supply, or investments advanced ahead of certainty risked being stranded.

It was judged that, in order to manage the risks and make better informed investment decisions, a much greater range of generation and demand scenarios should be studied than had hitherto been the case but that this would require automation of much of the power system analysis.

Although an existing tool was available – ESCORT [43], based on 'DC load flow' and with the facility to sample generation availability and vary demand levels – the opportunity arose to collaborate with EDF in France and share the costs of development of advanced new software that:

a) would permit the definition and execution of Monte Carlo assessments of system security;

b) would have a much more user friendly interface than ESCORT;

c) would make use of AC load flow and so allow study of voltage constraints;

d) could be integrated with a dynamic simulation tool (in this case, Eurostag [52] which has the benefit, among other things, of user definable controller models) and so allow study of stability issues such as those associated with imports of power from Scotland;

e) would be integrated with professional data analysis software;

f) could be configured so as to allow computationally heavy analyses to be farmed out to multiple standard PCs and so reduce the total execution time; and

g) with some extra in-house development, could be integrated with an NGC tool designed to generate credible generation capacity and demand scenarios.

EDF's main motivation was the analysis of uncertainty in operational planning timescales, i.e. year ahead down to day ahead and, especially, the ability to characterise voltage and transient stability limits. NGC agreed to join the project as a minor partner with development work being done by EDF and EDF bearing around 75% of the costs. However, NGC had an equal share in the design decisions. As the project went on, EDF began to recognise the potential for use in investment planning and NGC its potential for operational planning.

The project was delivered to specification, time and budget in 2003 and has been presented at a number of conferences and in a journal [42]. As the project was nearing its end, EDF was split up and the new French transmission system operator – RTE – inherited the project. RTE has made regular use of the tool ever since, mainly for special studies of weak areas of the system. It has claimed that it has allowed it to save upwards of €10 million in out of merit costs in respect of one constrained system boundary alone. It has recently embarked on a project to update the tool [53].

Within NGC – now National Grid – although it was already a user of Eurostag on which the Assess data format was based, it was necessary to invest significant time in the assembly of additional data not present in simple Eurostag files [52]. Training and then some weeks of familiarisation were then necessary before a pilot study could be performed in which it was found to be necessary to make further adjustments to the data. However, once a consistent set of data had been assembled, a couple of hours spent defining a study could allow computations to be carried out overnight that would have taken a few hundred person-hours to undertake by conventional means.

Statistical analysis was possible to discover both the limits on stable exports of power from Scotland and the conditions under which limits were lower than the maximum, and to have greater confidence in working closer to the limits than would have been possible using manual study methods.

Although the (unpublished) pilot study went some way to demonstrating the benefits of Assess, it has never been used by National Grid subsequently. One of the issues at the time was IT policy which required considerable documentation and layers of management to be navigated before approval could be gained for use of any new software that could not be regarded as a standard desktop application. In addition, by the time the software was developed and delivered, key managers who had supported the project had been replaced by others who did not feel the same degree of 'buy-in', either for the tool or for the concept of 'probabilistic planning' that it was designed to facilitate. However, it may also be recognised that the degree of 'churn' in the generation 'background' had reduced significantly in the meantime and the study of many scenarios was much less of a priority. Meanwhile, the company has since moved away from use of Eurostag towards DIgSILENT PowerFactory [8].

Perhaps one of the most significant issues around the use of Assess is the need for user expertise. The software is powerful but rather complex and, in spite of having a reasonable user interface, time is needed to become familiar with how to execute different functions. More importantly, a deep understanding is required of power systems, analysis of power systems (and its limitations) and of the analysis methodology enabled by Assess. Studies need to be designed carefully in order that the correct variables or system parameters are sampled in the right way in order to reach the objectives of the study, and some understanding of statistical analysis is necessary. While these requirements need not be insurmountable and can be met, for example, by team working, they are difficult to achieve in a department that is short-staffed or does not have individuals available with the right educational background or experience.

A.2 Advanced transmission planning tools elsewhere in Europe

One particular new tool in use outside of Britain is briefly described here. This is ESPAUT, developed by ERSE, now RSE, in Milan, Italy, largely as part of a research collaboration with Eirgrid in Ireland [54][55]. It complements another RSE tool, REMARK [56] and has been used in Eirgrid's Grid25 study [57] and in an offshore grid study [55][58][59].

Use of ESPAUT and REMARK has the following objectives:

- against a background of forecasted evolution of demand and production, find economic and adequate transmission expansion planning solutions;
- evaluate costs and benefits related to the different solutions.

ESPAUT determines the optimal expansion planning and REMARK performs an adequacy analysis of the reinforced system and calculates suitable statistical indices to compare alternatives.

ESPAUT works by considering [55]:

- both the operation of the system in one year with the network intact (base case) or subject to some N-1 outages;
- a complete representation of the electrical system via DC load flow equations with limits on active power flows through links;
- dispatchable, imposed and renewable generation with related limits in production and variable costs; and
- generation areas with limits in overall production.

Subject to the above and using the horizon year sub-divided into a limited number of 'characteristic' demand and production scenarios, it minimises the sum of [55]

- annualized investment;
- total variable production;
- total load shedding; and
- total penalty costs due to violation of production limits in generation areas.

An 'optimal' transmission expansion plan is found through the definition of candidate links with binary variables defined for each where a value of 0 indicates that the candidate link is not selected and 1 indicates that it is. Thus, it is a mixed integer linear programming problem that is very computationally intensive to solve. Its scalability to very large systems is open to question but it has been shown to work effectively for the Irish system.

It is the author's understanding that the tool should still largely be regarded as a prototype but it is already being used extensively by Eirgrid.

The main benefit seen by Eirgrid to date has been that it can allow a relatively fast[13] and quite detailed assessment (down to the level of individual network nodes and branches,

[13]A run of the tool will still take an expert user some hours to set up and a computation takes a number of days. Further time will be required to review the results and check their coherence.

not simply inter-area capacities) of the transmission system impact of major external developments such as very different generation backgrounds or demand growth. Among other things, this allows a transmission planner to engage in a highly informed manner with policy makers in respect of the implications for the transmission system of different policies.

In common with any complex, advanced tool, ESPAUT requires specialist users. Eirgrid has committed to a small number of individuals gaining, retaining and using that expertise and works closely with the tool's developers in Italy.

B. Case study – the existing transmission planning process: planning of the West Coast HVDC link

B.1 Background

Particularly since the introduction of the Renewables Obligation, there has been considerable interest from generation developers in the opportunities afforded by high average wind speeds in the North of Britain, not least in Scotland. This has led to a considerable number of generation connection applications that, together, would significantly exceed the transmission network's capability to securely export power from Scotland into England. As a consequence and in order to ensure continued compliance with the Security and Quality of Supply Standard (SQSS, [4]), the three GB transmission licensees have brought forward proposals to reinforce the network not only on the Scotland-England boundary (described as B6 in the Electricity Ten Year Statement [48]) but also within Scotland. These proposals have been considered and consulted on by Ofgem since 2004 under the general heading of 'Transmission Investment for Renewable Generation' (TIRG)[14] and, more recently following a study completed by the three transmission licensees in July 2009 for the Electricity Networks Strategy Group [60], in respect of 'Transmission Investment Incentives'[15].

One particular project has been proposed by National Grid Electricity Transmission (NGET) and Scottish Power Energy Networks (SPEN) in order to increase the capability to export power from Scotland, an HVDC project – the "Western HVDC Link", sometimes also known as the "West Coast Bootstrap" – with the following features [61]:

- a converter station at Hunterston, North Ayrshire;
- approximately 4km of high voltage direct current cable to a 'landfall', where the subsea cable comes ashore, at Ardneil Bay;
- a subsea marine cable approximately 385km long from Ardneil Bay to Leasowe on the Wirral peninsula;
- an underground high voltage cable of approximately 33km through the Wirral peninsula; and
- a converter station in Deeside, Flintshire.

The mass impregnated paper polypropylene laminate (MIPPL) DC cables being used in the project have an unprecedented voltage rating of 600kV and a current rating of 1825A. The continuous power transfer capacity of the link is 2.2GW.

A £1 billion contract for delivery of the project was signed by a joint venture of NGET and SPEN with a consortium of Siemens and Prysmian in February 2012 with commissioning planned to take place in 2016 although, in May 2014, it was announced that installation of the cable was being postponed having been due to start that month [62]. This case study briefly reviews the steps taken by NGET and SPEN to identify and justify the need for the project. The main source for what is reported here is [6].

B.2 Benefits assessed

It was asserted in the commentary on the project provided in [6] that treatment of wind and intermittent sources of generation was not clear within the SQSS at the time of development of the project. Thus, an explicit economic test was used. The scheme was justified if the following was true:

$$T + OUT < O + L$$

where:

T – Transmission Capital Costs, i.e. the capital costs of the reinforcement. In advance of running an extensive tender process, these were estimated based on discussions with suppliers and intelligence of similar projects world-wide.

OUT – Outage costs during construction, i.e. congestion costs that are forecast to be incurred during the transmission outages required to construct the reinforcement. In [6], it was noted that, in cases where a project involves reconductoring existing overhead line routes, these costs can be significant, greater than 10% of the capital cost. For this scheme, which involves new build offline with minimal outages only for connection of the new converter stations, the OUT costs were assessed as immaterial.

[14]See https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/transmission-investment-renewable-generation.

[15]See https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/transmission-investment-incentives

O – Constraint costs saved, i.e. the congestion costs saved over the lifetime of the scheme. Assessment of this element depended on an assumption of permanence of the current rules for constraint pricing in GB and of the current requirements that determine when constraints must be incurred to secure flows on the system.

L – Costs of transmission losses saved, i.e. the savings in transmission losses over the lifetime of the scheme. These were initially forecast on the simple basis of the difference in I^2R losses for the two network states without and with the Western HVDC, for a single flow condition from Scotland to England.

The benefits not assessed included competition benefits and reductions in wholesale electricity price, the change in unsupplied energy resulting from the scheme, the change in the total cost of maintaining the transmission network (noted in [6] as having been judged to be of order 0.1% - 1% p.a. of the capital costs), carbon costs, and, compared to the alternative of an onshore AC overhead line, environmental costs and benefits such as impact on visual amenity, reduced exposure to electromagnetic fields and lower disruption. It was noted in [6] that the scale of onshore overhead line developments (>300km from Central Scotland deep into Northern England) and the timescales to gain consents meant that it was accepted that an onshore overhead line was not a serious alternative to the Western HVDC.

B.3 Tools and data used

As noted above, a key element of the assessment was the forecasting of the costs of congestion, i.e. the costs incurred by constraining outputs of generators in order that secure network power transfer limits can be respected. In [6], this was described as a two-stage process:

1. assessment of the secure limits of power transfers across the main transmission boundaries;
2. use of boundary limits in an assessment of year-round congestion costs, with and without the reinforcement.

The first of the above was based on load flow assessments, initially using in-house software and later studies using DIgSILENT PowerFactory [8]. The second used a spreadsheet with Visual Basic macros, which were claimed to get close to the exact optimum of the constraint problem as formulated. (It was noted in [6] that an exact mathematical formulation such as a Linear Program was not readily available to NGET). A probabilistic spreadsheet add-on, @Risk from Palisade software [63], was used to perform Monte-Carlo simulations of Wind and Conventional generation availability at each demand condition.

The main variables considered in the economic assessment included the following:

- demand growth and power station openings and closures, postulated out to 2025 under 3 scenarios plus a sensitivity case for development of wind farms, and assumed in each scenario to be unchanged after 2025.
- network characteristics, with the GB transmission system represented as merely eight zones, in a radial 'tree' structure, separated by seven major transmission boundaries. The reinforcements were thus represented in the model as discrete increases in the boundary capabilities.
- generation capacity, represented as capacity totals by fuel-type within each zone. The merit order of station running to meet demand was represented at the fuel-type level.
- within year demand, represented by 24 conditions taken from a typical annual load duration curve. These conditions were eight for each season, from daytime peak to night-time trough, with three seasons: Winter, 'Summer-Intact' and 'Summer-Outage' (in which the reduction in boundary capabilities during transmission maintenance outages was represented).
- generation availability with availability rates of conventional plant taken from historical averages; for example, Gas and Coal stations were modelled at 80% in winter and 75% in summer. Wind generation was modelled from forecast distributions of wind load factors by location; annual load factors of 28% were assumed for onshore and 35% for offshore.
- prices to resolve constraints. It was assumed that increments of power in the importing area (termed 'Offers' in the GB balancing mechanism) are priced at ~ 160% of the wholesale power price, and that decrements of power in the exporting area (termed 'Bids' in the GB balancing mechanism) are priced at ~ 50% of power price, in line with historic observations. The Offer and Bid prices were modelled by fuel-type. Given that power prices were forecast to be of the order of £55/MWh, the typical forecast price of resolving constraints was thus 90 – 25 = £65/MWh.

The 'headline numerical results' reported in [6] were that the capital cost of the Western HVDC Link was likely to be of order £1000m. The central case constraint benefits, present-valued over 40 years of asset life, were assessed as £4900m, with a further £600m of identified savings in transmission losses. Under a lower and a higher scenario of GB system expansion, the constraint benefits were £2600m and £8800m. Other sensitivities, on both transmission and constraint prices, were assessed to be at least -30% to +40% on these numbers.

One particular feature of the scheme is the use of the highest rated voltage seen to date on any HVDC cable in the world. While this maximises the power transfer capacity, there is no publicly available information on how NGET and SPEN regarded any risks associated with the manufacture and commissioning of such a cable and it has already been noted that its installation has been delayed. Furthermore, while a converter fault would require an interruption to power transfer, both converter stations are understood to have been configured in such a way as to permit operation in a monopole mode with half the normal power transfer capacity until such time as the faulted elements are repaired. However, the lack of an earth return cable means that a fault on either of the two main cables would mean a reduction of power transfer capacity to zero.

B.4 Technical studies

Before a new HVDC converter station can be procured and commissioned a number of particular technical assessments should be carried out. These include the issues outlined in CIGRE Technical Brochure 186 [64] such as the basic project specifications – location, line length, number of poles, DC system voltage and nominal and overload power rating. However, there should also be assessments of the AC system short circuit level and loss of commutation risk, the need for harmonic filtering and the capacitor bank switching size. Specific controls, such as required rate of change of power or the need for supplemental controls, e.g. to contribute to system damping, and telecommunications requirements also need to be specified. Many of the details regarding implementation can be assessed by the manufacturer given suitable specification of limits. However, a number of system studies still need to be performed, including assessment of subsynchronous control interactions. It is the author's understanding that NGET no longer retains the expertise 'in-house' to conduct such studies and must hire suitable contractors who will bring suitable tools with them. In addition, in light of the transmission licensees' ongoing requirement to ensure stable transmission system operation, they will require suitable models of converter stations to be built into standard tools for assessment of system dynamic behavior. It is the author's understanding that this is not always straightforward.

C. An outline of a new approach to transmission system investment planning

Section 5.2 discussed two broad approaches to transmission network investment planning, one in which the network was modelled in great detail and another in which the network model was heavily simplified in order to enable the effects of uncertainties to be better understood. However, some issues were highlighted in respect of the latter. Instead, it has been proposed in a project led by the French transmission system operator, RTE, and involving the University of Strathclyde that:

- the method used to create a simplified representation of the network should be clear and repeatable [65]; and
- its use forms one stage in an iterative procedure such as that illustrated in Figure C.1.

The net transfer capacities (NTCs) used in step 4 should also use a clear and repeatable procedure that does involve modelling of the full system but only for a limited number of scenarios. Piecewise linear approximate costs of increases in NTC can be used in step 5 and should reflect, as far as possible, the cheap, easy actions that only have limited scope and the more expensive actions that would be needed to achieve significantly greater increases in NTC. The aggressive simplifications would enable practical sequential simulations of whole years or, indeed, multiple years to help inform an investment strategy. The outputs would be quasi-optimal NTCs that might be higher than those at present. The approach proposes that a more precise design and costing of the achievement of increased NTCs should be carried out using the full system model for a limited set of representative operational scenarios, not least in order that alternatives to primary assets are properly evaluated including in respect of their reliability and any risk of widespread system disturbances as a consequence of control action failures[16]. The analysis informing this would be of a similar form to that shown in Figure C.2. Then, if it reveals a solution different from that represented by the assumed NTC upgrade cost used in step 5, the piecewise linear cost function is revised and steps 5 and 6 are repeated.

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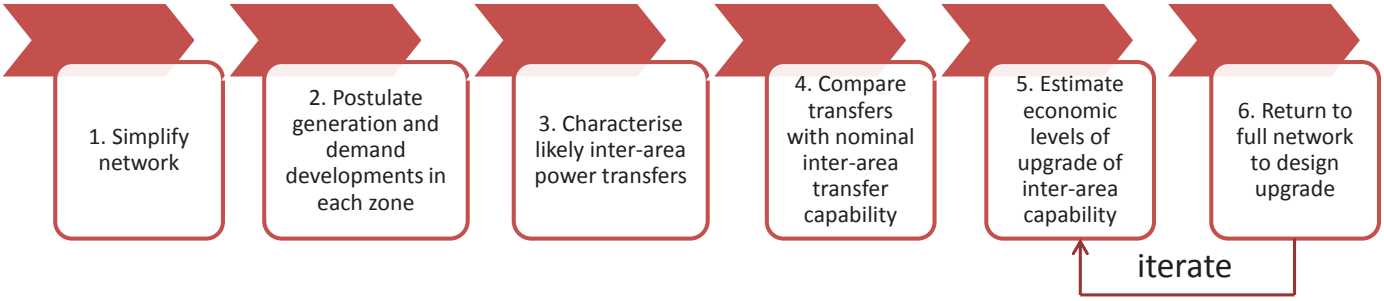

Figure C.1: A proposed iterative approach to transmission planning that allows many scenarios to be studied.

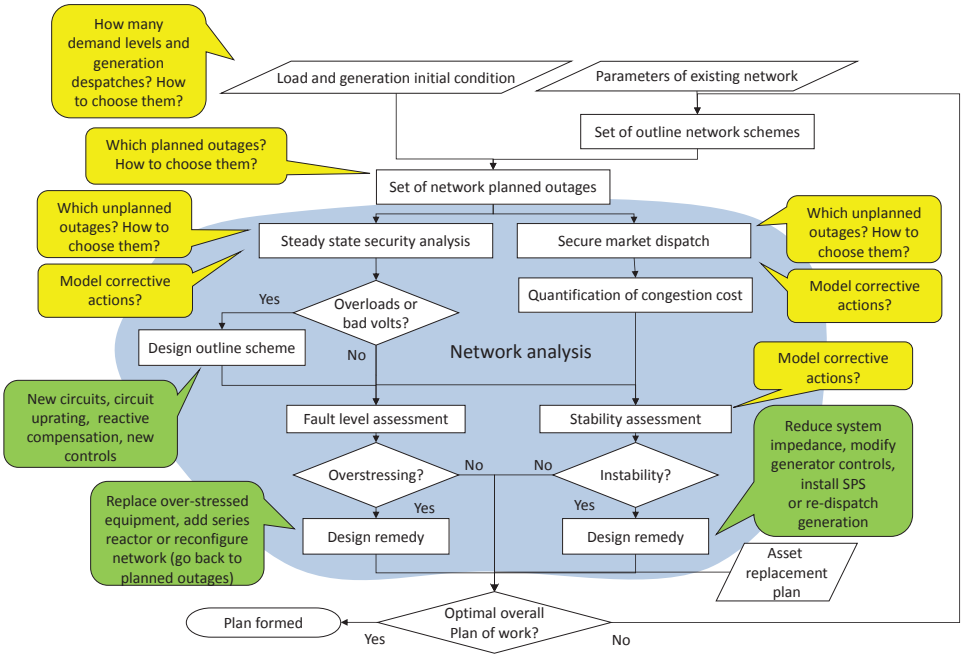

Figure C.2: Detailed study of the facilitation of a given increase in net transfer capacity.

[16]Many major system disturbances or blackouts worldwide, perhaps the majority, have involved either the failure of operators to realise that narrow network margins have been exhausted, or incorrect performance of automatic controls such as protection systems [1]. The former might be due to inadequate monitoring or inadequate models; the latter might involve a protection failure and, as a result, backup protection operating and removing more than one primary element from service. Often, protection tripping when it should not have done, such as generator protection maloperating, exacerbates a problem. Narrowing of pre-fault margins and greater reliance on automatic actions to manage faults on transmission networks would, ordinarily, appear to increase the risk of major disturbances. At the very least, a system operator's ability to evaluate the risks would appear to be necessary [66].

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