The Role of Risk Modelling in the Great Britain Transmission Planning and Operational Standards

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***Abstract*—This paper presents three case studies of risk-based standards from Great Britain: the pre-liberalisation generation planning standard, the present method for deciding operational reserve requirements, and the transmission network planning standard. These illustrate a number of key issues in developing planning and operational standards for wind, including: the benefits of risk-based standards in adapting to new circumstances; the importance of considering model assumptions carefully when interpreting risk calculations; consequences of the difficulty in calculating an absolute level (and hence cost) of risk; and the need to account for uncertainty in system background data such as the future plant mix when developing network planning methodologies. Robust standards make a vital contribution in achieving an appropriate balance between system cost and reliability. The transmission network planning standard is studied in particular detail, especially how the present combination of deterministic and probabilistic sections might evolve for use in a future power system with a very high renewable penetration.**

***Index Terms*—Power system planning, Power system operation, Power system reliability, Risk analysis, Wind energy**

I. Introduction

INTEREST in new power system risk assessment methods has increased in recent years, due to the increasing penetration of variable-output renewable sources worldwide. Precisely because of this variable output, probabilistic analysis is the natural mathematical language for analysing systems with high renewable penetrations. In particular, traditional N-1 planning criteria, where the network should be secure against the loss of any single component (whether generator or network branch), does not naturally account for renewable generating units whose available output varies continuously between zero and rated capacity. The elements of risk to be analysed might include both loss-of-load, and the financial risks arising from the possibility of constraining generation.

This paper presents three case studies on the use of risk modelling in the Great Britain power system, and draws more widely applicable lessons from these studies: the pre-liberalisation generation security standard (Section II), the system operator's reserve setting method (Section III), and the current review of the transmission planning standard (Sections IV and V). Finally, in Section VI conclusions are presented.

The key themes are the benefits that a basis in probabilistic risk analysis brings when adapting standards to new circumstances, the need for careful examination of both model structure and underlying assumptions when interpreting risk calculation results, consequences of the difficulty of calculating an absolute level of risk, and the difficulties inherent in making large investment decisions under uncertainty about other aspects of the future power system.

II. The Historic Generation Security Standard

This provides an example of a risk-based standard which, while the underlying risk calculation has a fairly simple structure, may naturally be extended to new circumstances. It also illustrates the importance of examining carefully the assumptions underlying a model when interpreting its results, or when applying the 'headline' figures for risk results in new circumstances; this provides a useful case study of issues to consider when interpreting modern risk calculations.

A. Description

The generation fleet in Great Britain is not centrally planned at present; it is assumed that the 'energy only' market (without capacity payments) provides sufficient incentive for new capacity investment. In the nationalised industry in England and Wales which existed pre-1990, there was a risk-based generation planning standard (he description of the standard in this section derives from [1], [2], unless otherwise stated.) This was based on winter peak Loss Of Load Probability (LOLP, i.e. probability that generation is insufficient to meet demand) and was designed for application seven years ahead of the operating year. The England and Wales system pre-liberalisation used mostly thermal generation (largely coal, with nuclear being developed latterly), with some pumped storage hydro capacity in Wales. The assumptions underlying the calculation were:

- 'Failure' defined as the need to disconnect load, assuming that demand would first have been reduced by 7.5% via voltage and frequency reductions.

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- Independent Normal distributions for available generation capacity and peak demand.
- Available generation capacity distribution has
  - Mean 85% of installed capacity,
  - Standard Deviation (SD) 3.75% of ACS peak demand.
- Annual peak demand distribution has
  - Mean equal to ACS peak demand.
  - SD of 3.87% due to weather effects alone, and 9% due to uncertainty in the underlying demand level 7 years ahead.

Though not explicitly stated in [1], an assumption of independence allows combination of the various distribution SDs as square-root-of-sum-of-squares. ACS (Average Cold Spell) peak demand is defined as 'a level of peak demand within a financial year which has a 50% chance of being exceeded as a result of weather variation alone' [3]; it is the standard measure of underlying demand level used in GB, and is distinct from the year's peak demand out-turn.

The original 'headline' risk target used in the planning standard was 3% winter peak LOLP, which was equivalent to a 28% plant margin (of installed generation capacity over ACS peak demand), or a 23% chance of voltage or frequency reductions. In 1986, a proposal was developed on cost-benefit grounds to change the standard to an LOLP of 9% (margin of 24%), balancing the cost of lost load against that of investment in new plant. Details of this cost benefit analysis are not available in the surviving reports; a general discussion of the difficulty in calculating the required absolute value of risk will be presented in Section V.

B. Application to Present Day Planning Calculations

1) Significance of Assumptions:

There are a number of assumptions, both explicit and implicit, which must be taken into account if the old generation planning standard is to be used as a target risk level in modern system planning studies.

- The standard was defined with respect a very particular risk calculation; the target risk levels therefore cannot be applied to other risk calculation structures.
- The 'headline' risk concerned the probability of the available generation being less than 92.5% of demand and demand disconnection being required, not the probability of available generation being less than full demand and voltage/frequency reductions being required.
- The standard was for meeting England and Wales demand from native generation only. From the 1980s to the present, import from Scotland or France has generally been possible at times of high demand.
- 'Failure' in the risk calculation defined above is usually referred to as LOLP. However, [1] notes that short lead time plant such as open cycle gas turbines would have been built if the alternative had been running a high risk of demand disconnection in the operating year.

2) Justification of Standard:

It is widely accepted that, even where more accurate data and model structures are available, it is extremely challenging to calculate an absolute level of risk (see e.g. page 5 of [4]). The true (if unstated) justification for the generation standard was therefore that over a number of decades it consistently delivered an adequate degree of demand security at an acceptable cost, rather than the 'headline' risk figure. If it had consistently failed to deliver sufficient generating plant in the operating year, it seems unlikely that it would have remained unchanged whatever the headline target risk figure.

3) Extension to New Technologies:

As discussed above, the risk calculation underlying the generation security standard had a very simple structure, and closely-defined parameters. One great benefit of this risk-based deriviation of the plant margin standard, however, was that it could naturally be extended to new circumstances. In an all-conventional-plant system, it would be a straightforward matter to use updated mean plant availabilities, or to revise the SDs representing demand uncertainty, without the need for wholesale rewriting of the standard. It would also provide the basis for modifying the risk calculation to include wind generation also, provided that a suitably robust probability distribution for available wind capacity at time of annual peak were available.

III. The System Operator's Reserve Setting Standard

This brief case study provides an example of a risk-based standard which has been extended naturally to include wind generation, and hence provides a practical illustration of the benefits of probabilistic risk-based standards in adapting to new circumstances.

A. Role of the standard

The level of reserve to schedule is not set as part of the System Operator's (SO's) licence; however, the licence does specify a duty to maintain system frequency with 0.5Hz of nominal. The regulator gives the SO a target figure to spend each year on reserve procurement, and the SO is incentivised to beat this target [5]. The SO, National Grid, has an internal risk-based standard for determining the 4-hour-ahead Short Term Operating Reserve Requirement (STORR); a simplified version of this, which the SO has made publicly available, will be described next.

B. Description

1) Distributions:

The level of contracted STORR is driven by three components (this description follows Appendix A of [6].) All of these are random variables, and under an assumption of independence a probability distribution for the reserve which is called on may be derived by convolving the three individual distributions:

- Scheduled conventional capacity becoming unavailable: mean 600 MW and SD 600 MW (the form of the distribution is not specified).
- Demand forecast error (DFE): modelled as Normally distributed with mean 0 and SD 450 MW.
- Wind forecast error (WFE): distribution based on historic data from metered wind farms.

2) Target:

For each half hour period, STORR is contracted 4 hours ahead such that there is a probability of 1/365 that this contracted reserve will be insufficient. This is clearly inspired by the number of days in a year. However, as for the historic generation (see Section II-B2) this should be regarded as a target for risk as calculated in a particular calculation, rather than an absolute risk level; its justification in practice is that it delivers an acceptable level of operational security at an acceptable cost. Indeed, the annual duration of reserve shortages is typically just a few hours per year, much less than the 24 hours the target would suggest [7].

3) Extension to New Circumstances:

This risk-based model provides a clear basis for inclusion of wind forecast error in the STORR evaluation. It also provides a very natural way of modifying the volume of reserve as forecast errors change due to a more diverse wind resource, the wind resource forming a greater proportion of the overall power generation, or as better forecasting techniques become available. It will be seen in the next section that a lack of such a clear basis to a standard makes it harder to extend the transmission network planning standards to a system with a high wind penetration.

IV. The GB Transmission Planning Standard 1: 'Deterministic' Part

This section provides a case study of a standard originally derived for an all-conventional system, whose extension to include variable output renewables has been complicated by the lack of a clearly documented first principles derivation.

A. Typical Deterministic Planning Standards

In general, 'deterministic' network planning standards are relatively simple heuristic rules designed to give a reasonable solution to a complex underlying probabilistic planning problem. The GB 'deterministic' planning standard is unusual among deterministic standards in that it provides a formula for the total required transfer capability across any boundary drawn in the system.

This is very different from more typical N-1 or N-2 network planning standards which state that the network should be able to operate normally under certain defined contingencies. For instance, the Irish standard [8] specifies certain combinations of generator and branch outages which should not cause demand disconnection, voltage violations, or system instability.

Two complications issues may be noted regarding N-x standards:

- There is no risk analysis element in ranking the importance of outages for consideration.
- Conventional generating units (whose availability is to a good approximation 'all or nothing') fit an N-x picture better than many renewable technologies (whose availabile capacity varies continuously between zero and maximum depending on natural resources).

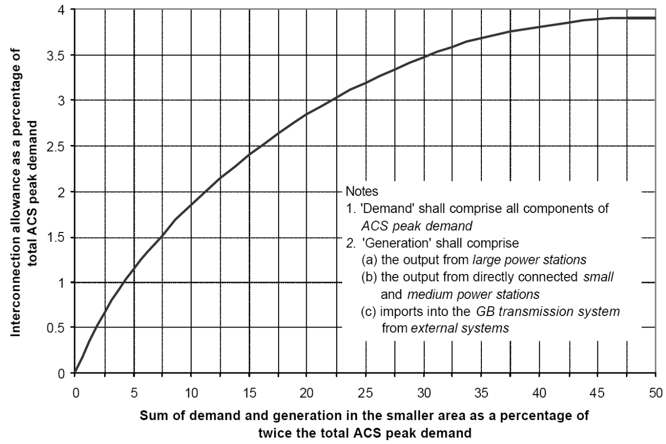

Fig. 1. The present 'Circle Diagram' from the GB determistic planning standard. The 1950s Circle Diagram had the same shape, but the x- and y-axes were labelled 'Group maximum demand as % of aggregated maximum demand' and 'Maximum unbalance as % of aggregate maximum demand'.

B. The Great Britain Deterministic Standard

1) Introduction:

The first part of the GB Security and Quality of Supply Standard (SQSS) [3]) criteria relating to development of the main interconnected system is a 'deterministic' rule which was originally based on a statistical analysis of required power transfers. It states that for any boundary drawn across the transmission system, the required capability for transfer of power across the boundary is the sum of

- *The Planned Transfer (PT)*: this is a central estimate for the required transfer at time of annual peak
- *The Interconnection Allowance (IA)*: this additional capability is designed to take account of variability about the central estimate (the PT) due to plant unavailability, fluctuations in demand etc.

In the next paragraphs, this deterministic standard will be described in its historical context, followed by a discussion of its adaptation to include wind generation.

2) History:

The Interconnection Allowance originated in measurements of actual required transfers between regional electricity authorities in England and Wales between 1943 and 1948[1]. It was calculated from the 'Circle Diagram' (so-called because of its shape, see Fig. 1); this is an envelope of the maximum observed imbalances between the two parts of the system, as a function of the proportion of total system demand located in each area.

At that time, generation in each authority was planned to meet local demand, with interconnection being planned for reserve sharing only. The Circle Diagram was used to predict what interconnection capacities would be required as demand continued to grow; this synthesis of observed transfer requirements would not cater for all possible requirements

[1]Much of this historical material has been not been published except in internal reports which are not now easily available. This section is based on archive research and interviews conducted by Keith Bell. Further information may be found in his presentations at [9]

in the long-term, but it would be expected to represent a high percentile of possible future requirements. Through the 1950s, the new 275 kV interconnected system would have been planned on this basis.

In the late 1950s and early 1960s, central planning of generation and transmission capacity was conducted by the Central Electricity Generating Board (formed in 1958). The notion of an 'interconnection reserve' about a normally regionally balanced power system was no longer sufficient – some recognition would be required for the expectation of bulk transfers from central generation on the coal fields of northern England and south Wales to the largest demand centres in the centre and south-east of England. This was formalised in the system planning standards of 1976, which specified a transmission capability across any boundary equal to a 'planned transfer' under typical peak conditions *plus* an interconnection allowance. Justification of transmission capacity above this deterministic minimum on economic grounds was also permitted [10].

3) Implementation of the current GB planning standard: The calculation required by the present deterministic standard consists of three stages (a detailed tutorial-style description of this methodology may be found in the consultation document at [9]):

1) Reduce the transmission-connected generation to an effective 20% plant margin, by ranking plant according to 'likelihood of operation at times of ACS peak demand'; the lowest-ranked are termed 'non-contributory' and disregarded [3].
2) Scale back the output of all remaining contributory units so that forecast ACS peak demand is met precisely. All conventional plant has the same scaling factor; an additional scaling must be applied to wind due to its different availability properties. The resulting power flow gives the Planned Transfer across any boundary.
3) The Interconnection Allowance for each boundary is obtained from the circle diagram as in the original 1950s methodology[2]. The required transfer capability for each boundary is then the sum of the PT and IA.

C. Discussion

The Interconnection Allowance element of the standard was originally derived for a system where interconnection between areas was used for reserve-sharing only. Its origins therefore lie in risk management. However, while the notion of the IA helping manage loss of load risks remains intuitively reasonable in a system with bulk transfers driven by the economics of generation, there is no first-principles derivation underpinning the deterministic standard in its modern form. Justification for its continued use must there rest on it delivering a sufficient degree of demand security, and access to demand for high merit generation, at a reasonable cost.

The existence of a risk-based derivation for the historic generation planning standard (which dates from the same era, see Section II) would have provided a natural means of extending this to include wind generation; the lack of this has indeed been a major issue in adapting the standard for wind generation. There is in fact not even an explicit statement of the purpose of the deterministic standard, i.e. whether it is about equal market access for generators independent of location, or about demand security.

The GB Transmission Licensees recognise that the present planning standard may be not be satisfactory with a high renewables penetration. A review of the standard was thus carried out with the aim of identifying appropriate scaling factors for wind [11], but its results have not yet been implemented. The only explicit guidance on the factor is that 'generating units outputs shall be set to those which ought reasonably to be foreseen for that [ACS peak] demand'. No statutory guidance is given as to the specific scaling factor to use to account for the variable nature of wind generation; the present practice by the licensees is use a scaling factor for wind of 72% on a scale where that for conventional plant is 100%. Any value chosen is therefore open to reasonable challenge by parties whose judgment differs and would leave justification of transmission reinforcements dependent on explicit economic analysis (see Section V).

As part of the current planning standard review, the deterministic standard has been 'reverse-engineered' it to quantify what it delivers in risk terms [9]. In this context Keith Bell, one of the present authors, has proposed a risk-based planning model based on demand security and generation equal access to markets, expressed through a (higher-dimensional) successor to the circle diagram which would account directly for wind generation.

V. The GB Transmission Planning Standard 2: The Role of Probabilistic Planning

This section discusses the role of probabilistic planning techniques in the GB planing standards, and how they may be used in the context of high wind penetrations.

A. The Current Standard

1) Economic Justification and Constraint Costs: Under the present standard, additional investment above the deterministic standard is justified on economic grounds, provided that the investment cost is lower than the net present value of operating costs which would otherwise arise (Paragraph 4.4 and Appendix E of [3]). Importantly, such an economic justification must by definition be made on a year-round basis; in recent years, high costs of constraining generation[3] have been seen at relatively low demands during summer transmission maintenance outages (see Chapter 5 of the consultation at [9].) With various issues regarding the deterministic standard remaining unresolved, transmission

[2]Except that the x-axis has been altered to the sum of generation and demand in the smaller part of the system under PT conditions, expressed as a percentage of twice total demand; when this change to the axis label was made the shape of the diagram was left unchanged.

[3]In the GB system, the market first determines a generation schedule assuming no network constraints, and the System Operator (SO) invites from generators bids to change their output levels in order to give a feasible power flow. The SO therefore sees the market price of the redispatch very directly.

upgrades in recent years have been justfied on grounds of constraint cost reduction [12].

2) Uncertainty in Investment Drivers: Application of this economic standard is complicated by uncertainty in the future system background to be used in the cost-benefit analysis, including demand levels, data availability for renewables, fuel prices, per-MWh constraint costs, changes in renewables subsidy and carbon tax regime, generation location, and location, plant mix and availability properties of generation.

Even under an assumption of perfect data, it is not straightforward to calculate an absolute level of expected constraint costs (as opposed to comparing *relative* constraint volumes for different investment options); this view of the role of risk modelling is widely acknowledged in the literature, e.g. Page 5 of [4]. As constraint costs tend to live in the tails of probability distributions (while the annual volumes are substantial, within the GB system it is unlikely that a high proportion of the planned flow across a particular boundary would be curtailed all the time), predictions tend to be very sensitive to both data and model structure assumptions.

This issue of data uncertainty has been considered to an extent in recent investment decisions [12]; it will be more important still in future decisions driven by much larger and more geographically diverse renewables development. Possible resolutions will be discussed in Section V-B.

3) Interaction with Transmission Access:

At present in Great Britain, firm access rights to the transmission network for the rated capacity of a station are habitually sought by generation developers; the generator is compensated when its output is curtailed. Such firm access is arguably much less suitable for variable-output wind generation than for conventional plant, as wind generates at near maximum output for a small proportion of the time (for a review of transmission access issues in GB, see [13].). If more flexible access products become available, under which wind is not always compensated when it is curtailed, this would have consequences for the network planning standards. Such flexible access arrangements would benefit wind generators by reducing use-of-system charges, and by increasing opportunities to connect new capacity.

B. Future Standards

1) Evolution of the Present Standard:

As the penetration of renewables increases, most of it located in areas remote from the main load centres, the amount of transmission investment it drives will clearly also increase (a recent report has suggested that 5 billion of network investment will be required over the next decade [14].) It will remain the case that most transmission investment to connect wind generation will be justified on economic grounds (driven by constraint costs), due to wind's limited contribution to securing peak demand [15]. In one sense, this would not require a substantial change to the economic part of the present standard; transmission investment could still be made on economic grounds, balancing the net present value of capital and constraint costs as discussed in Section V-A.

As discussed in that section, due to uncertainty in input data such as the generation background, there can be no definitive answer as to which of two investment options is better in economic terms within the scope of the planning standard. Equivalently, it is not possible to determine mathematically an 'optimal' investment strategy, even in stochastic optimisation terms, due to the difficulty in quantifying the uncertainty. At present, the standard is implicitly framed in terms of requiring such a definitive result, although in practice a sensitivity analysis over a range of wind capacities was performed for the most recent major decision [12].

A planning methodology should drive network investment decisions that are robust against a wide range of possible future scenarios of generation mix, fuel prices, demand, etc.; this uncertain future makes a degree of 'judgement call' unavoidable. This is particularly so in a decentralised industry without central planning of generation. If this can be achieved with a degree of determinism in the standard, then the need case will be less open to challenge in planning enquiries.

2) Load Shedding Costs:

It has also been proposed [16], [17] that load not supplied should be included in the cost-benefit analysis calculation, as an alternative to the deterministic part of the present standard. This brings three further complications, beyond those described in the previous section on constraint costs:

- *A per-MWh value of lost load is required.* On an operational timescale, it would be natural for the System Operator to use either the cost of voluntary load curtailment, or the level of regulatory incentive for involuntary load-shedding. On a planning timescale, it is necessary to consider the value to society of demand security, for which no such natural value is available. Moreover, it is doubtful whether the consequences of a large increase in energy not supplied can be quantified simply in monetary terms, or whether it should properly be discussed in wider public policy terms.
- *Rarity of loss-of-load.* While constraint costs are small as a proportion of the total energy market, constraints are commonplace and are incurred on a daily basis. Involuntary loss-of-load events involving transmission-network-owned equipment, however, are much rarer, and mostly involve demand connections [18]; the last customer disconnection event in GB due to absolute adequacy issues in generation and the main interconnected transmission system was in the mid-1960s.
- *Nature of loss-of-load events.* Most cases of voltage reduction or disconnection of load are due to fault events, for which in hindsight insufficient response or reserve had been scheduled on the system, whether as a whole or in key locations.

The extreme scarcity of relevant events makes modelling the level of loss-of-load risk exceedingly difficult, even if the aim is only to compare risk under different investment options. Calculating an absolute level of adequacy risk is more challenging still, before the additional complications of placing a financial cost on this risk have been considered. Furthermore, the multiplicity of rare fault-type events, and the dependence of the consequences on the system's dynamic response, makes putting a cost on this aspect of risk even harder than costing adequacy risk. However, opinion is presently divided as to whether this approach of including loss-of-load costs in the cost-benefit analysis will be productive; one major programme of work is investigating the possibility [17], aiming to obtain directly a cost-effective solution to transmission planning.

An alternative means of including demand security risk directly in the standard would be to set a target value for a particular well-defined risk calculation (for instance the 'Security Approach' proposed in [9]). This need not necessarily aim to calculate an absolute risk level, and in this sense is inherently more robust than the cost-benefit analysis. Two of the difficulties described above (rarity of loss-of-load events, and their domination by fault events) would however remain.

3) Role of the Present Deterministic Standard:

Our view is that the present deterministic standard is more explicitly based on generation equal access to the market than about demand security. Nevertheless, it does define the degree to which the network restricts demand security, and over the years it has been widely acknowledged as delivering an acceptable level of security at a reasonable cost [10]. It is therefore attractive to allow it to continue to serve this role in the future, given the difficulty of including a demand security element in the planning process via a cost-benefit analysis.

If it is accepted that most of the network expansion to connect wind will have to be justified by balancing projected constraint costs against capital costs, the present deterministic standard (but with a lower scaling factor for wind generation) might provide a useful means of specifying a minimum permitted transfer capacity across transmission boundaries on demand security grounds. Moreover, there have been recent moves in the US to include a 'stressed dispatch' condition in transmission planning guidelines, which could be regarded as analogous to a demand security justification for the present GB deterministic standard [19]. This suggests that concerns about the robustness of a pure cost-benefit approach are shared internationally.

VI. Conclusion

This paper has presented three case studies of the use of risk standards in the Great Britain power system, namely the historic generation planning standard, the System Operator's reserve setting method, and the transmission planning standards. A number of important general points, which are applicable to other systems, are demonstrated in these studies:

- When interpreting risk calculations, it is vital to consider the structure of the calculation and the accuracy of the input data, as well as the 'headline' result for the risk level.
- Calculating an absolute level of risk is very challenging, and hence the headline figure for a risk standard might not be transferable between calculations with different structures or data. The ultimate justification for risk standards is whether in practice they deliver acceptable levels of performance at an acceptable cost.
- Probabilistic risk based standards may very naturally be extended to new circumstances, such as revised input data, or the arrival of new generation technologies with different properties.
- Network planning methodologies must take into account the uncertainty in the future system background (generation, demand etc); defining how to analyse a planning option's performance in a single scenario is not on its own sufficient. Due to the difficulty in quantifying this type of uncertainty, the planning methodology must necessarily involve a degree of judgement call on which option best hedges against the different possible futures.
- However, given that a need case must be defended robustly to regulators and planning enquiries, this dependency on judgment and uncertain market data should be minimised (consistent with proper consideration of the uncertain generation and demand background).

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