

A COMPOSITE METHODOLOGY FOR EVALUATING NETWORK RISK

Simon BLAKE
Durham University - UK
s.r.blake@durham.ac.uk

Philip TAYLOR
Durham University - UK
p.c.taylor@durham.ac.uk

David MILLER
CE Electric UK - UK
david.miller@ce-electricuk.com

ABSTRACT

This paper addresses the problem of measuring network risk, both present and anticipated, in a part of the network where multiple factors are involved. A composite methodology has been developed to evaluate the impact on network risk of several factors, and in particular to assess the interaction of these factors. This methodology is illustrated by a case study based on an actual part of the UK network. It is used to evaluate the growing level of risk in each year before transformer replacement can be justified, and thereby determine the optimal year for such replacement under a number of different possible scenarios. The conclusion is that, in a portfolio of possible capital investment projects, many of which have more than one driver, some can be postponed for a number of years with little increase in network risk, while postponement of others would result in an excessive increase in network risk. The methodology presented in this paper enables such projects to be ranked and scheduled in a way which minimizes total network risk for a fixed capital expenditure profile.

INTRODUCTION

Distribution networks in developed countries are generally capital intensive and in order to retain the expected level of customer service the volume of ageing assets that need to be replaced is steadily increasing. For example, the GB energy regulator approved a 32% increase in asset replacement spend at the last periodic review [1]

Replacement of ageing assets is not the only driver for capital investment. There are many others, including safety and environmental. Two in particular feature in this paper. One of them is reducing the expected duration of customer disconnection in the event of an unplanned outage. Here, network automation has the potential to improve restoration times. The other is network reinforcement, to increase the capacity of the network to cater for the expected future load growth. In the UK, load growth has been below 1% per year on average since 1970 [2], but is likely to increase at a faster rate during the period 2010-2030 as a result of increasing use of electric vehicles and heat pumps [3, 4, 5]. As a result of these competing needs for capital expenditure out of a limited budget, priorities need to be decided by the distribution network operator (DNO). In GB, this is done in consultation with the national industry regulator, OFGEM. This process of allocating priorities tends to work within separate categories of investment. For example, in the most recent distribution price control review (DPCR), implemented in April 2010, the health of each asset has to

be determined and reported on a scale of 1 to 5, and this scale is used to determine a programme for asset replacement. The peak demand at each load point on the network also has to be determined and reported on a scale of 1 to 5, and this scale is used to determine a separate programme for network reinforcement [6].

In this paper, it is argued that separating these programmes can lead to sub-optimal decision making when allocating limited capital resources. There may be areas of the network where a combination of asset replacement, network reinforcement and increased automation can reduce the level of network risk more effectively, in terms of value for money, than can be achieved by considering each driver separately. A methodology is developed to measure this increased effectiveness, and is illustrated by a case study based on an actual location on the distribution network in the North East of England.

Research Background

This separation of drivers for capital expenditure, which is a feature of industrial practice in the UK, tends to be reflected in the literature. There are a number of useful studies on the optimisation of asset replacement, in particular using condition based risk management techniques [7, 8]. Other studies concentrate on network reinforcement, which is the primary driver in areas where the network is still expanding [9]. In the UK, this was the case before about 1970 [10], and may be the case again during 2010-2030 if the rate of take-up of electric vehicles and heat pumps is significant [3, 4, 5]. There are also several relevant studies on the benefits of increasing automation, in particular regarding self-healing networks, both at transmission level [11], and on medium voltage distribution circuits e.g. 11 kV [12, 13, 14]. However, there appears to be a gap at the higher distribution voltages (33, 66 and 132 kV in GB) with which the present paper is particularly concerned. A suite of methodologies for evaluating network risk under a range of different network configurations and operating strategies has been developed by the present authors [15, 16, 17]. These methodologies have in general been applied to one driver at a time. In this paper, a combination and extension of these methodologies allows multiple drivers to be considered together, as is explained in the following section.

COMPOSITE APPROACH

In situations where two or three drivers could be combined, their interaction may lead to an optimal solution which could not be reached by considering each driver separately.

However, the selection of appropriate methodologies, and deciding how and in what order to apply each of them, and then how to interpret the results, is not usually straightforward. It requires expert engineering input, and a detailed understanding of the network problem being addressed, as well as an understanding of the different methodologies that can be used. This requires a more heuristic approach than those described in [15], [16] and [17]. It has therefore been developed not theoretically but rather heuristically, with reference to a number of individual case studies. This approach is explained with reference to one such case study, based in an urban and suburban network in the North East of England.

Urban and Suburban Case Study

Figure 1 shows the relevant 66 kV urban and suburban network schematically. The focus of the case study is at primary substation 'A', which contains two 66 / 11 kV transformers and supplies around 19000 customers (peak load around 30 MVA). There is significant 11 kV interconnection with primary substation 'C', and also with the 20 kV primary substation 'B' (via four 20 / 11 kV transformers at two sites, not shown in Figure 1). 'A' is supplied via a 66 kV ring, which includes an industrial site whose transformers are masked from 'A' by circuit breakers (and therefore not shown). These idiosyncratic complications are typical of high voltage distribution networks, and are the reason why generic methodologies are less appropriate in assessing their reliability than would be the case either for medium voltage distribution networks, or for transmission networks.

The interacting issues which affect possible capital investment in this part of the network include:

- Ageing transformers at 'A', which will reach their 50 year nominal lifetime in 2018.
- Possible annual load growth averaging 2.5% during 2010-2030, due to take up of electrical vehicles and heat pumps.
- Possible 11 kV transfer between substations. In particular, the transformers at 'C' were renewed and their rating increased in 2009.
- Possible rationalisation of the network by removing two of the 20 / 11 kV transformers and reallocating 11 kV feeders.
- Possible automation of 11 kV switchgear (90% of which is presently manually operated) at critical locations in the networks interconnecting the substations.
- Possible increased use of active network management (ANM).

Approach Adopted

There are several possible ways of approaching the composite question of determining the optimal investment strategy for this network. The method that has been adopted

uses a three stage approach:

- Evaluate the level of network risk for the customers at 'A' year by year, as the condition of the transformers deteriorates with age, both with and without transformer replacement, to determine an optimal year for replacement.
- Add in the effects of increasing utilisation, to determine when the transformers would need to be replaced anyway, regardless of age, to cater for the additional load. Determine to what extent this could be deferred by strategic feeder reallocation.
- Determine whether automated network reconfiguration, in conjunction with ANM, could further defer the requirement for capital expenditure, given both the ageing assets and the projected load growth.

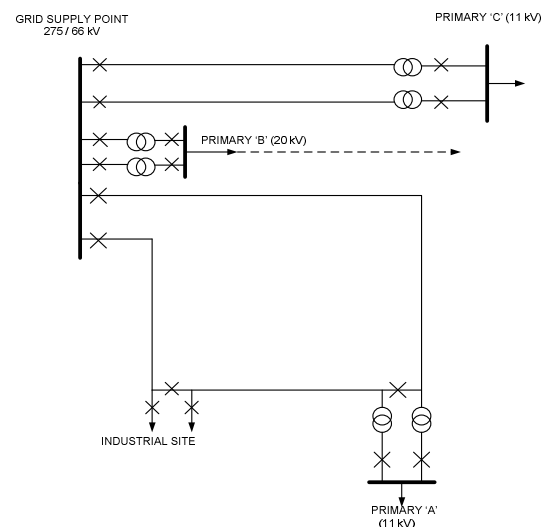


Figure 1: Case Study Network

STAGE 1

Basic network risk (the expected annual cost of unscheduled repairs, accelerated asset deterioration as a consequence of failures, and penalties imposed by the regulator for customer loss of supply) can be calculated for 'A' assuming average failure rates, using the methodology developed in [15], [16] and [17]. It comes to £23.8k per year.

The effects of transformer ageing can be factored in using exponential relationships between age and health index (HI), and between HI and failure rates, as assumed in [8]. On this basis, the calculated risk of £23.8k applied when the transformers were 30 years old, in 1998. The corresponding figure for 2010 is a slightly greater £26.0k, increasing rapidly to £30.5k by 2015, £49.0k by 2020, and £88.1k by 2023, all as a consequence of the higher expected failure rates of the existing ageing transformers. Although the failure rates of other assets in the network will also be

increasing with time, this has not been included in these calculations to enable the effects of transformer ageing alone to be identified.

Although the risk in 2023 (when the transformers will be 55 years old) is significantly higher than the present level, the annual expected risk reduction arising from replacing the transformers with new ones is still under 5% of the capital cost of their replacement. On economic grounds alone, this would probably not justify the investment. However, when the need to replace ageing transformers is combined with the increasing need to reinforce the network, the balance of costs and benefits changes, as described in Stage 2.

STAGE 2

At this stage, it is further assumed that:

- Network rationalisation removes two of the four 20 / 11 kV transformers fed from 'B'.
- 11 kV feeder reconfiguration is implemented to take maximum advantage of the increased transformer capacity at 'C'.
- Peak load growth averages 2.5% per year from 2010 onwards.

Peak loads are then calculated for each year as in [17], to determine the last firm year (LFY) as implied by the current UK regulatory design standard P2/6 [18]. This turns out to be 2015, in which year substations 'A' and 'C', as well as the remaining 20 / 11 kV site fed from 'B', are all at between 98% and 100% of their rated capacity. The LFY criterion is that, in the event of a single circuit failure, the full peak load can be supported by the remaining parallel circuit.

This implies that, although the network risk due to the ageing transformers at 'A' has only increased slightly by 2015, as shown in Stage 1, the transformers may need to be replaced anyway in that year with higher rated transformers (accompanied by appropriate reconfiguration of 11 kV feeders) in order that the network remain firm for several more years of 2.5% load growth. There is, however, an alternative approach, involving network automation and ANM. This alternative is explored in Stage 3.

STAGE 3

In Stage 2, the requirements of P2/6 were applied separately to each of the three primary substations, to conclude that the LFY would be 2015. However, in practice ANM can be deployed by the control engineers in any planned or unplanned (n-1) situation. For example, inspection of the detailed 11 kV diagram indicates that 18% of the load (measured at the time of system peak) at 'A' has alternative connections via a normally open point (NOP) to 'C'. Likewise 24% of the peak load at 'C' has alternative connections via a NOP to 'A'. In the same way, there are connections between 'A' and 'B', between 'B' and 'C', and

from 'A' to another supply point on a different network. In all, 73%, 78% and 43% of the loads at 'A', 'B' and 'C' respectively are transferable at 11 kV.

In the event of a circuit failure at 'C' (which has the least transferability), up to 43% of the load could be transferred to either 'A' or 'B' within 90 minutes. So, for example, by 2023, a further 8 years of 2.5% load growth means that transformers are normally loaded to just over 60% of rating. If one transformer fails, even at a time of peak load, it would be possible to transfer 20% of that load to either 'A' or 'B', leaving 80% on the remaining transformer at 'C', which would now be loaded to just under 100% of its rating for the duration of the fault. A similar argument applies to failures at 'A' or 'B'.

If ANM of this kind is acceptable to customers and to the regulator as guaranteeing security of supply, then the LFY of this network can be extended from 2015 to 2023 and possibly beyond. Extending the LFY beyond 2023 is theoretically possible, but by that time the network, in particular the ageing transformers, will be stretched close to its limit. In practice, 2023 is the LFY under this ANM scenario. However, it still enables the replacement of the two transformers at 'A' to be deferred by 8 years as compared with Stage 2, to a year of rapidly increasing failure rates as shown in Stage 1. Replacing them with larger units in 2023 would then be justified, but for a combination of reasons, including both replacing aged assets and reinforcing the network to comply with the design standard.

One further point requires consideration at this stage. The manual reconfiguration of 3 or 4 feeders (closing NOPs) might take a total time of around 90 minutes. During this time, for customers to remain connected at times of peak load, the remaining working transformer would be loaded to 120% of its rating, which would not be desirable. If these NOPs were partially automated by installing radio control, this time could be reduced to around 15 minutes, incurring a lesser risk. If the NOPs were fully automated, including circuit breakers and self-healing control algorithms, the time could be reduced to below 3 minutes. The question is, whether the cost of partial automation of around 12 NOPs, or the somewhat greater cost of full automation, could be justified by this expected reduction in risk.

Calculation suggests that this reduction would be around £5.5k per year in 2015, increasing to around £25.9k by 2023 with older transformers, and reducing back to below £5.0k once the transformers are replaced. These figures are for a partial automation project, the overall benefit of which would depend on the capital cost. The rate of return is most attractive for the few years before the transformers are replaced. On this basis, the automation project could be justified, subject to more detailed calculations.

CONCLUSIONS

In this paper, the methodologies previously developed to evaluate issues of asset replacement, increasing utilisation and network automation have been combined and applied to a case study which includes aspects of all three issues. This heuristic and holistic approach is less theoretically based than the three parent methodologies, but is instead based on the unique features of the case study under consideration, interpreted by expert engineering judgment. As a result, it is a more versatile technique than the parent methodologies. It is also potentially more powerful, in that it can explore the interrelationships of different factors applied to a single region of the network.

The diverse issues of asset ageing, reallocation of loads, expected annual load growth, active network management, levels and locations for automation, and major capital expenditure need to be factored in to the decision making process, and they cannot be considered separately and independently, as they impact on one another. A composite problem on the network must first be recognised as such. It can then be treated by a composite approach, whereby expert engineering judgment is used first to formulate the problem concisely, and then to apply appropriate methodologies in sequence, but mutually interacting, to lead to an optimal solution. This solution is likely to be closer to an optimal solution than could be achieved by applying the methodologies separately and in isolation.

REFERENCES

- [1] Electricity Distribution Price Control Review Final Proposals (144/09), OFGEM, December 2009
- [2] G. Boyle, B. Everett, J. Ramage, 2003, *Energy Systems and Sustainability*, Oxford University Press
- [3] G. Ault, D. Frame, N. Hughes, N. Strachan, 'Electricity Network Scenarios for Great Britain in 2050', Final report for OFGEM's LENS project, November 2008.
- [4] 'Project Discovery: Energy Market Scenarios', OFGEM Consultation Document, October 2009, accessed 15.09.10 via www.ofgem.gov.uk
- [5] D. J. C. McKay, 2009, *Sustainable Energy without the Hot Air*. Downloaded from www.withouthotair.com, 15.03.10
- [6] Distribution Price Control Review 5. Last accessed 20.09.10 via www.ofgem.gov.uk/Networks/ElecDist/PriceCtrls/DPCR5/
- [7] W. Li, J. Zhou, J. Lu, W. Yan, 2007, "A Probabilistic Analysis Approach to Making Decision on Retirement of Aged Equipment in Transmission Systems", *IEEE Trans. on Power Delivery* (2007) pp 1891 -1896
- [8] D. Hughes, P. Pschierer-Barnfather, T. Pears, "Condition Based Risk Management (CBRM): Bringing Excellence in Asset Management into the Boardroom", *CIRED 20th International Conference on Electricity Distribution, Prague, June 2009*.
- [9] I.J. Ramirez-Rosado, J.L. Bernal-Agustin, 2001, "Reliability and Costs Optimisation for Distribution Networks Expansion Using an Evolutionary Algorithm", *IEEE Trans. on Power Systems* (2001), pp. 111-118
- [10] L. Hannah, 1979, *Electricity before Nationalisation*, Macmillan, London
- [11] K. Moslehi, R. Kumar, 2007, "First Aid for Power Grids", *Power Engineer*, IET Oct/Nov 2007
- [12] P. Deschamps, J-C. Orsini, 2009, "On the Field Autonomous Automatism: A Complementary Way for Network Automation", *CIRED 20th International Conference on Electricity Distribution, Prague, June 2009*
- [13] P. W. Cox, 2009 "Self-Healing Networks: Performance Improvement by Automated Switching Algorithm", *CIRED 20th International Conference on Electricity Distribution, Prague, June 2009*
- [14] D. Macleman, W. Bik, A. Jones, 2009, "Evaluation of a Self Healing Distribution Automation Scheme on the Isle of Wight", *CIRED 20th International Conference on Electricity Distribution, Prague, June 2009*
- [15] S. R. Blake, P. C. Taylor, A. M. Creighton, 2008, "Distribution Network Risk Analysis", *MedPower '08 Conference on Power Generation, Transmission and Distribution, Thessaloniki, Greece, November 2008*
- [16] S. R. Blake, P. C. Taylor, A. M. Creighton, 2009, "Methodologies for the Analysis of both Short-Term and Long-Term Network Risk", *CIRED conference 2009, Prague, Czech Republic*.
- [17] S. R. Blake, P. C. Taylor, A. M. Creighton, D. Miller, 2010, "Optimal Investment Planning through Balancing Load Growth with Network Risk", *CIRED workshop 2010, Lyon, France*.
- [18] Engineering Recommendation P2/6 'Security of Supply', Energy Network Association Engineering Directorate, July 2006