Experiences of Automatic Contingency Selection Algorithms on the NGC System

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Abstract: An essential aspect of modern power system security assessment is the consideration of any contingencies which may arise due, for example, to planned or unplanned outages of lines, and which may cause system overloads or abnormal system voltages. Several methods have been developed during the last few years to address this problem and within the National Grid Company, the ΔP^2X outage ranking process has been used in the past. However, this ΔP^2X outage ranking method may not identify those critical outages associated with relatively low ΔP^2X changes. The paper reports on investigations carried out to determine which simplified methods would ensure that all voltage-based severe outages were identified.

Introducion: The National Grid Company plc (NGC) owns and operates the transmission system in England and Wales. This consists of a main 400 kV network and subsidiary 275 kV networks around major demand centres. The system is heavily meshed and consists largely of double-circuit transmission lines. It is connected, via supergrid transformers, to the distribution networks (operated at voltages of 132 kV and below) which are owned by the Regional Electricity Companies. The transmission system is also connected to generators owned by separate generating companies. In addition, there are interconnections to the French and Scottish electricity transmission systems. As well as maintaining the infrastructure of the transmission system, NGC has the role of coordinating the despatch of power generation to meet demands whilst honouring safety and security standards. NGC is also required to facilitate competition in the generation and supply of electricity.

An essential aspect of modern power system security assessment is the consideration of any contingencies which may arise due, for example, to planned or unplanned outages of lines, and which may cause system overloads or abnormal system voltages. For power systems consisting of several hundred lines such as the NGC network, it is impractical to examine all possible contingencies using ac load flow analysis. Therefore, the engineer makes a judgment, based on intuition and experience, of those contingencies which require ac analysis. An automatic contingency selection algorithm can assist this process by providing an objective criterion to select the most critical contingencies in a given system state in order to limit the number of contingencies being studied.

Ideally, one full ac powerflow must be solved for each contingency. Even by applying fast computational techniques, it is not possible to carry out an exhaustive test of single, double and multiple contingencies. Several methods have been developed during the last few years to address this problem. Within the Company, the ΔP^2X outage ranking process has been used in the past. However, this ΔP^2X outage ranking method may not identify those critical outages associated with relatively low ΔP^2X changes. Therefore, an investigation was carried out to determine which simplified methods would ensure that all voltage-based severe outages were identified.

The objective of this paper is to report on the experiments carried out and the results obtained. The paper describes:

- Features of accurate voltage-based contingency selection algorithms
- Some of the dc-based techniques investigated
- Application of a powerflow solution for voltage-reactive power screening
- Comparative analysis of these methods.

Voltage-Based Contingency Ranking Methods: Two accurate voltage-based contingency ranking methods described by Lo et al (1989) were investigated and implemented for reference purposes while considering only low voltage cases. Realistic bus voltage and Mvar weighting factors were obtained from the EMS AC Contingency Screening function at the National Grid Control Centre and 132 transmission line outages simulated using NGC=s ac loadflow program. Lo et al (1989) assumed unity bus voltage and MVar generation weighting factors in their analysis; this approach was not adopted here to avoid misrankings. Technically, from the Q-V curve, a small voltage change may correspond to a large increase in reactive power and this phenomenon may become more pronounced for severe contingencies.

$$P\,I_1 = W_v \Sigma_\alpha \left(\frac{\left(V_i^{pre-cont} - V_i^{post-cont}\right)}{max\ allowable\ volt\ drop} \right)^2 + W_Q \Sigma_\beta \left(\frac{\left(Q_1 - Q_i^{mid}\right)}{\left(Q_i^{\max} - Q_i^{\min}\right)/2} \right)^2 + W_C \Sigma_\gamma \left(\frac{\left(Q_1 - Q_i^{mid}\right)}{\left(Q_i^{\max} - Q_i^{\min}\right)/2} \right)^2 \quad (1)$$

where the maximum allowable voltage drop assumed is 4 percent

α = set of buses with voltages outside the limits: $0.97 < V_i < 1.04$ pu.

β = set of generators with reactive power violations i.e. those that violate the constraint: $Q_i^{\min} < Q_i < Q_i^{\max}$

γ = set of SVC buses with reactive power violations i.e. those that violate the constraint: $Q_i^{\min} < Q_i < Q_i^{\max}$

Q_i^{mid} = reactive power limit midpoint = $(Q_i^{\max} + Q_i^{\min})/2$

Also, $W_v = 30.0$; $W_Q = 1.5$ and $W_C = 0.5$ are used as weighting factors. These weighting factors are designed to give a practical method of tuning the performance index based on NGC operational experience. In theory, they reflect the fact that voltage magnitudes and reactive powers are strongly related and they bring the voltage/reactive power concepts to a common base. However, screening on low voltage problems was considered to be of prime importance in these experiments.

As stated in the literature, the masking effect may not have been eliminated with the above performance index. By masking, we mean a situation whereby a very severe contingency with a large voltage step change in one node is ranked the same as a less severe contingency with many lower voltage step changes across many nodes. If the index in equation (1) is increased from 2 to say 3 or 4, the final ranking may be worse due to increased non-linearity of the problem. To provide a compromise between masking and misrankings of the contingencies, the performance index defined in equation (2) was also investigated. This index is similar to equation (1) except that a new term has been added to give extra emphasis to the highest among all voltage violations caused by the contingency under consideration.

$$P\,I_2 = W_v \max\left\|\left(V_i^{pre-cont} - V_i^{post-cont}\right)\right\| + W_v \Sigma_\alpha \left(\frac{\left(V_i^{pre-cont} - V_i^{post-cont}\right)}{\max\ allowable\ volt\ drop} \right)^2 + W_Q \Sigma_\beta \left(\frac{\left(Q_i - Q_i^{mid}\right)}{\left(Q_i^{\max} - Q_i^{\min}\right)/2} \right)^2 + W_C \Sigma_\gamma \left(\frac{\left(Q_i - Q_i^{mid}\right)}{\left(Q_i^{\max} - Q_i^{\min}\right)/2} \right)^2 \quad (2)$$

Alternative DC-Based Voltage Ranking Methods: The use of dc-based voltage ranking techniques is based on the fact that:

- When a transmission outage occurs, the current previously flowing in that branch must find alternate paths;
- The voltage changes in the system nodes due to an outage are essentially due to the fact that the increase in P^2X is much more significant than the loss of BV^2.

Therefore, the active power flow changes in the branches of these alternative paths and the resultant change in their reactive power loss result in changes in the node voltage magnitudes. Consequently, the significant voltage changes are expected to be monitored at the nodes traced by these alternate paths.

Several performance indices based on dc loadflow analysis (including the ΔP^2X ranking technique) were derived and described below.

Performance Index Based on ΔP^2X Changes: The change in the reactive losses, ΔP^2X, following a fault can be determined by

$$P\ I_3 = \Delta P^2 X = \Sigma P^2 X_{(contingency\ case)} - \Sigma P^2 X_{(base\ case)} \qquad (3)$$

for all lines. However, PI_3 may not identify critical outages associated with relatively low P^2X change. The assumptions made in deriving equation (3) are that the:

- Real power flow is sufficiently larger than the reactive power flow;
- Reactance (X) of a line is much greater than its resistance (R).

The first may not always hold for all system conditions, especially where reactive power flows are causing severe voltage problems. However, the second assumption is reasonable for NGC networks.

Performance Index Based on Incremental Branch Active Power Flow Criterion: For an incremental branch real power flow, DP_{ij}, across line i–j, define

$$PI_4 = \Sigma \left\| P_{(contingency\ case)} - P_{(base\ case)} \right\| = \Sigma \|\Delta P\| \qquad (4)$$

for all lines in the system.

Performance Based on Incremental Change in Branch Angle Criterion: This index aims to detect a diversion of a high level of power flow through a high-impedance path, by simply looking at the sum of the changes in the nodal angle (caused by the outage) of the lines.

$$PI_5 = \Sigma \left\| \Theta_{(contingency\ case)} - \Theta_{(base\ case)} \right\| = \Sigma \|\Delta\Theta\| \qquad (5)$$

Performance Index Based on the Concept of Contingency Stiffness Index: Meliopoulos et al (1994) described a criterion to identify those contingencies that may give rise to a high degree of non-linearity in the power equations. For the outage of a circuit connecting buses i and j, this index is defined as:

$$P\ I_6 = \max\left(\frac{P_{ij}}{Y_i^{eq}}, \frac{P_{ji}}{Y_j^{eq}} \right) \qquad (6)$$

where P_{ij}, P_{ji} are the active power flows at the two ends of circuit k; Y_i^{eq}, Y_j^{eq} are the equivalent admittance of buses i and j.

Other Indices: Some of the other localized indices investigated were:

$$P\ I_7 = \max \|\Delta P\| \qquad (7)$$
$$P\ I_8 = \max \|\Delta\Theta\|$$

Development of Approximate AC Loadflow Technique: In this Section, the details of the approximate loadflow technique investigated will be reported. Essentially, it consists of two stages (Ejebe et al, 1988):

Definition of a Voltage Subnetwork: Using the P^2X criterion, determine the location of buses with potential voltage problems. Determine

$$P\ I = \left\| P^2\ X_{(contingency\ case)} - P^2\ X_{(base\ case)} \right\| \qquad (8)$$

for all lines in the system. All those buses connected to branches whose PI exceeds a specified limit would be selected as belonging to the voltage subnetwork.

Application of an Approximate Power Flow Solution for Voltage-Reactive Power Screening: A simplified approach for voltage-reactive power screening is to use the nodal angles calculated by the ac loadflow program to compute the reactive power mismatches ΔQ at all the nodes comprising the voltage subnetwork; these have already been determined above. The changes, ΔV, in the bus voltage magnitudes can be computed only once with an approximate loadflow method. Thereafter, appropriate performance indices can be implemented. For the experiments carried out, two indices were investigated:

(a) Starting with the initial base case voltage magnitudes and post-fault angles from ac loadflow, evaluate the post-contingent voltage changes, ΔV. Then determine the performance index:

$$P\ I = \Sigma_\alpha (\Delta V)^2 \qquad (9)$$

for only the significant values of ΔV. In practice, α, will represent those buses identified earlier. The software was developed and firstly experimented on the IEEE 14-bus network. The approximate voltage values, ΔV, when compared with the exact voltage magnitudes from fully converged ac loadflow solutions (for single and double outages) were satisfactory—a maximum error of 0.6 percent was recorded. Though this method was found to be satisfactory for the well-conditioned, IEEE network, it was not very good (though encouraging) for NGC network because:

- Of the large number of controllable devices present in the network—these were contributing severely to the non-linearity of the problem;
- Even for the base case ac loadflow solution, there were generators and OLTCs at their limits.

The effect of these limits were already corrected during the ac loadflow simulations hence an attempt was made to reflect this in the post-contingent cases. However, it was computationally too slow and still inaccurate even with detailed modeling of the generators and OLTCs likely to hit their limits. Even the use of the results obtained after 2 iterations of the algorithm did not significantly improve the results.

(b) Starting with the base case voltage magnitudes (V_0) and post-fault bus angles from ac loadflow, evaluate the post-contingent voltage magnitudes (V_1). Determine the percentage voltage step change as

$$\%\ \text{voltage step change} = \frac{V_1 - V_0}{V_0}.\ 100 \qquad (10)$$

Comparative Analysis of Results: The rankings of the performance indices PI_1 and PI_2 are generally similar for the severe voltage-based outages; this is expected due to the high weighting factor used to emphasize interest in low voltage cases only.

The indices in equations (4), (5) and (7) were eventually abandoned because the outcomes of the rankings were not very satisfactory. However, the hybrid combination of the system-wide index given in equation (3) and the localized index in equation (6) was found to be satisfactory: 9 out of the 10 worst outages were identified.

For some of the contingencies, the buses with the worst voltage step changes evaluated using equation (10) corresponded to those derived from the ac loadflow results. This development is therefore encouraging - more investigations are on-going to improve on the modeling techniques.

Conclusions: An approximate ac loadflow and dc-based voltage ranking methods have been described in this paper. Though the results of the approximate ac loadflow are not very satisfactory, they are sufficiently encouraging for more investigations to be initiated on how to improve on the modeling employed. For the hybrid technique, this is a new approach for the identification of severe contingencies and has been shown to be suitable for large power systems with a high degree of nonlinearity such as the NGC network. No one method of contingency ranking is ideal for all networks because localized network details often override general considerations. The severity of contingencies should ideally be assessed according to the implications for capital expenditure, keeping in mind the requirement for overall security of the transmission system.

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The Energy Market in Norway and Sweden: The Spot and Futures Markets

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Abstract: This paper describes current philosophy and operational features of spot and future markets in the deregulated environment of the electric power industry in Norway and Sweden. The details of how bids are constructed and settlement of future contracts are illustrated using some examples.

Introduction: This PES Letter describes the operation of the spot and futures markets serving the deregulated electric power system in Scandinavia (presently Norway and Sweden), in some detail, with examples, for the normal, uncongested case. A previous letter [2] has provided an overview of the power system and deregulated structure. Congestion will be discussed in detail in a future letter. Deregulated spot market operation in Norway started in May, 1992, using procedures from a market for excess energy that had operated at low volumes since 1971. Sweden joined the market in January, 1996. Both spot and futures markets are owned and operated by Nord Pool, a company equally owned by the Independent System Operators (ISOs) Statnett and Svenska Kraftnät in Norway and Sweden respectively. The ISOs are owned by their respective national governments.

Spot Market: The spot market, also called the hourly market or 24 hour market, is the principal mechanism for generating competition among suppliers and purchasers of electric energy in Norway and Sweden. Operation is quite simple. Bids for all 24 hours of a given day are accepted and settled on the preceding day. Electric energy producers and purchasers submit bids to the spot market between 10.00 and 12.00 (noon) on the preceding day. Bids are submitted by organization, not by generator or specific load. Each hour's bid consists of linear segments connecting price and quantity. Table 1 shows a few hours of an example daily bid. Figure 1 shows a graph of the bid for hour 17. The bidding company is willing to buy power for prices between 0 and 170 Norwegian Crowns (NOK)/MWh, and is willing to sell power (negative quantities) for prices above 170 NOK/MWh (7 NOK ≅ 1 $US).

Table 1. Example daily bid (part), MWh/h

Hour	Price									
	0	10	101	150	151	170	171	200	201	900
10	80	—	—	—	80	0	–10	–30	–30	–30
11-16	100	100	100	100	80	0	–10	–10	–30	–30
17	80	70	70	60	50	0	–20	–30	–30	–30

Bids are aggregated into a demand (load) curve and a supply (generation) generation curve, and then these are crossed to obtain a spot market price (or clearing price) called the *system price*. For example, suppose that the aggregate load bid is the hour 17 bid of Figure 1, (without the negative values, which are generation bids), and the aggregate generation bid is given in Table 2. These curves cross (Figure 2) at a system price of 125.5 NOK/MWH and a quantity of 65 MWh.

Table 2. Example generation bid

Hour	Price					
	0	100	101	150	151	170
17	0	60	60	70	70	150

Bidders are notified of results by 14.00, and then have 30 minutes to make complaints. These are resolved, and a final schedule determined, by 15.00. The final price is posted on the Internet at http://www.nordpool.no/. Operation on the schedule starts at 00.00 of the given day. Successful bidders receive or pay the system price for energy. Thus the load above would pay 125.5 NOK/MWh x 65 MWh = 8,157.5 NOK for energy during hour 17 to the Nord Pool market.

Bids are accepted, and users are notified of market settlement, by fax, and also by electronic communication using a communications package called EDIEL, which is based on UN/EDIFACT, a United Nations electronic communications standard for industrial uses, and X.400 email. About a third of the participants, generally those with larger volumes, make use of electronic communication. Internet based communication is planned to start shortly, but there is still a lot of faxing. Bidders have the option to indicate that the same bid is valid for several days.

Spot market participation is not mandatory, with certain exceptions related to congestion that are not discussed here. Based on 1996 load figures, about 16 percent of energy used in the area covered by the Nord Pool market is traded on the spot market. This includes about 38 percent of the energy used in Norway, which has used the market longer than Sweden. Spot market volume (Figure 3) was less than 10 percent of area energy consumption for the first three years of operation. Volume experienced a significant increase when the futures market changed to financial settlement in week 40 of 1995. Futures contract holders who want to make or receive physical delivery of electric energy now buy or sell it in the spot market during the contracted week, where previously they had settled the contract by physical delivery with separate generator scheduling. Since that time, volume growth has paralleled futures market volume growth. Price in the spot market (Figure 4) has been largely determined by water supply in the hydro-dominated power system. 1994 and 1996 have been low water years, while 1995 and 1997 have not.

The simple market resolution process means that must-run issues, such as where water from upstream hydro plants that cannot be stored in downstream reservoirs must be used or spilled, can be handled by a zero price generation bid that simply accepts the market price for the

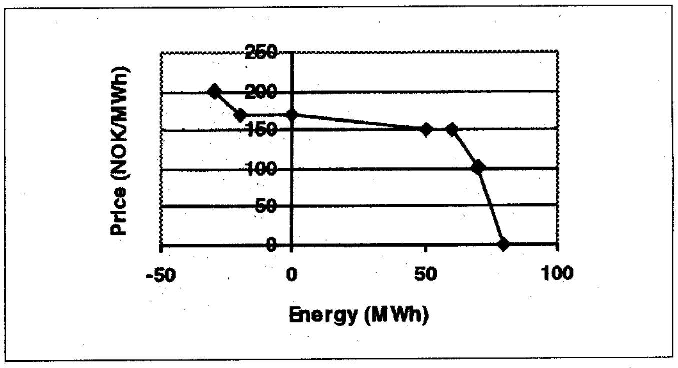

Figure 1. Hour 17 spot market bid

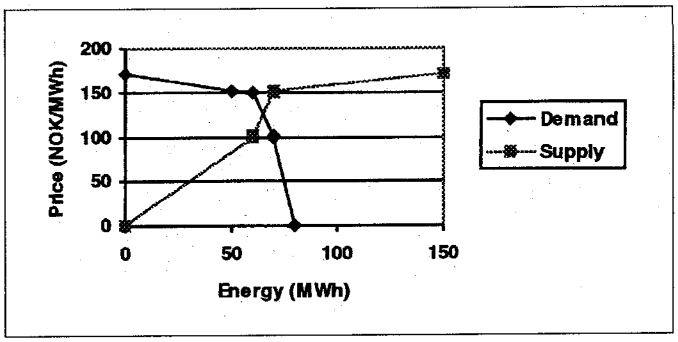

Figure 2. Spot market resolution