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Scenario selection in composite reliability assessment of deregulated power systems

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ABSTRACT

Power market analysis should be incorporated in reliability assessments of deregulated power systems. For the Nordic power system, this is done by using The Multi-area Power-market Simulator (EMPS) for long-term power market analysis, where EMPS finds the optimal socio-economic dispatch on a weekly basis, with respect to, e.g., hydro reservoir levels. The EMPS analysis results in a set of load and generation scenarios, and these scenarios are interpreted as a sample of future power market behaviour, and is used as basis for a reliability assessment. These load and generation scenarios are referred to as power market scenarios.

The power market analysis produces a large number of power market scenarios, and to include all these scenarios in a reliability assessment results in excessive computation time. The scenario selection method is presented and discussed. Scenario selection is used to pick out a subset of the generated power market scenarios, to only use this subset of scenarios as a basis for the reliability assessment. The paper provides some general guidelines for application of the scenario selection method. It is shown that the scenario selection method can reduce the scenario set by about 90%, with little loss of accuracy in the reliability assessment.

1. Introduction

In power system reliability analysis, probabilistic analysis is a very popular and useful technique for objective assessment of the power system reliability level, both for long-term adequacy assessment and short-term security analysis [1]. The system reliability is affected by, e.g., forced outages, maintenance schedules, load level, and generation dispatch. With more and more intermittent generation built into power systems, an increasing share of the generation system has a stochastic nature. This causes an increase in the variability in the generation scenarios compared to those of conventional power systems where the generation system mainly consisted of thermal and coal power plants.

In most restructured and deregulated power systems, there is no single central operator who has full control over the system, as the generation and transmission systems are handled by independent companies, and the load and generation schedules are determined by bids in the power market. Thus, the power market behaviour should not be neglected when load and generation scenarios are modelled in reliability assessment of deregulated power systems.

When the reliability assessment is based on Monte Carlo simulation techniques [2], load and generation scenarios are generated by random sampling. The generated scenarios reflect the stochastic nature of intermittent generation, but these scenarios are usually generated without considering how the power market affect the generation and load scenarios. In analytical techniques, the reliability assessment is usually based on one load scenario only, typically the heavy load situation. To make a connection between the power market and the generation and transmission system models used in the reliability assessment, a power market model is used to generate load and generation schedules for the power system under study [3]. The discussions and analyses in this paper focus on the Nordic power system. However, the ideas and methods should be very relevant for analysis of other deregulated power systems, but adjustments might be necessary due to, e.g., different market structure.

The Nordic power system is a hydro-thermal power system, but an increasing share of the generation capacity is wind power. The Multi-area Power-market Simulator (EMPS) [5] is designed for simulation of hydro-thermal power systems, where the market analysis is done by finding the optimal socio-economic dispatch

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considering, e.g., different hydro inflow scenarios and unit commitment costs. In EMPS, the stochastic nature of hydro inflow is included in the analysis by using historic weather data as expected future hydro inflow scenarios. Wind speeds and temperatures are also coupled with the historic weather data [6]. Typically, 50–75 years of historic data are used in the EMPS analysis, with a planning horizon of 3–5 years. The load model (used in EMPS) is defined to approximate the expected load in this 3–5 years period. The EMPS analysis yields a set of load and generation scenarios, which are referred to as power market scenarios. These power market scenarios are interpreted as possible future power system states, after market clearing, and used as a basis for a reliability assessment. The annual variation in hydro inflow, wind speed, and temperature is represented by the historic data, while the variation in load and generation schedules on a daily, weekly, and seasonal basis, within a given year, is represented by the power market scenarios EMPS generated for that year. Thus, the generated power market scenarios are regarded representative for the load and generation profiles over the whole year. The (up to) 75 years of historic data is a way of representing the stochastic variability in generation due to weather (hydro inflow, wind, and temperature), and is not to be interpreted as 75 years of planning.

For each of the hydro inflow years, the dispatch optimisation in EMPS is done for each hour within a week, or by splitting the week into different load periods. For instance, considering 5 load periods per week for 75 years of historic data, gives 19,500 different power market scenarios. This high number of scenarios results in very high computational requirements for the reliability assessment [3].

The scenario selection method, first presented in [7], is designed to reduce the number of power market scenarios that has to be analysed in the reliability assessment. The scenario selection method finds groups of similar power market scenarios, and then, for each group, chooses one scenario to represent the group characteristics. The set of chosen scenarios is denoted the representative set, and only these scenarios will be analysed in the reliability assessment. This will keep the sample variation of the full sample of power market scenarios more or less intact, but at the same time severely reduce the computational requirements of the reliability assessment. Ref. [7], discusses the scenario selection method on a very general basis. In this paper, a set of general guidelines for practical applications of the scenario selection method is presented. In addition, it is shown that the method works for both a small test networks and a large (real size) power system.

A short description of the power market analysis is found in Section 2. The incorporation of power market scenarios in the reliability assessment, and the evaluation of reliability indices, is discussed in Section 3. The scenario selection method is dealt with in Section 4. In Sections 5 and 6, two case studies are included to illustrate the application of the scenario selection method. The case studies are followed by some final remarks in Section 7 and a conclusion.

2. The Nordic power market

Deregulation of the Nordic power system took place in the 1990s and early 2000s [4], and a common Nordic power market (Nord Pool) has been established. The Nordic transmission system is operated by four TSOs – Energinet.dk (Denmark), Fingrid (Finland), Statnett (Norway), and Svenska Kraftnät (Sweden).

In addition to being responsible for the real time operation of the transmission system, the Nordic TSOs defines available transfer capacities (ATCs) between market zones [4]. Market zones are defined such that transmission corridors with a high anticipated load connect different zones. In situations where the market clearing for the whole system leads to too high power flow through one or more of these corridors, the market zones are used to split the system into price areas, to reduce the power flow through these corridors.

The organisation of the Nordic power market is illustrated in Fig. 1. In the financial market, long term contracts are traded, where the main purpose is hedging against price fluctuations. In the day-ahead market, physical power is traded, and at noon the market clearing is done for each hour of the following day according to the supply and demand curves. The price for each hour is determined by the intersection of these two curves. The market clearing is first done for the whole system, but if this leads to violations of one or more of the ATCs, the market zones are used to split the system into two or more price areas.

After the market clearing in the day-ahead market, TSOs trade power in the balancing market to, e.g., resolve congestion problems within market zones or provide spinning reserve. Balancing power is traded in the pre-operational and operational phase in Fig. 1, where both demand response and reserve generation can be bought. For more details about the Nordic power market, see, e.g., [4,8].

A special characteristic of the Nordic power system is the high share of large reservoir hydro power plants. Hydro power covers about 95% of the installed capacity in Norway, and about 45% of the installed capacity in Sweden. The rest of the installed capacity consists of some nuclear power plants in Sweden and Finland, and thermal generation in Denmark and Finland. In Denmark, 34% of the installed capacity consists of wind power. There are some wind farms in the other countries, with more to be built in the future.

2.1. The power market model

EMPS-NC (Network Constraints) [6,9], an extension of EMPS, is used for the power market analysis. In EMPS-NC, transmission constraints (the ATCs) are included in the dispatch optimisation, as a linearised power flow is used to check each scenario to ensure that the dispatch does not result in too high power flow through corridors connecting market zones. The TSOs can define ATCs on a daily basis, while market zones are defined for longer time periods – market zones are updated in case of long-lasting structural changes in the power system, e.g., a new transmission line coming into service, while ATC are changed more frequently due to, e.g., maintenance work or forced outages. For the long-term power market analysis in this paper, the market zones and ATCs are kept constant for the whole analysis period, since it is difficult to make assumptions about how these change over time.

EMPS-NC models loads per bus, and production per generator, in the analysed power system. Thus, the generated power market scenarios are suitable as a basis of both generation and transmission system reliability assessment.

3. Incorporating power market scenarios in the reliability assessment

Depending on the time resolution of the dispatch optimisation (hourly or by load periods), EMPS-NC predicts the system state for that hour or period after the market clearing, which so far has been referred to as a power market scenario. In the reliability assessment in this paper, the reliability indices are calculated based on the OPAL methodology [10]. In the OPAL methodology, an operating scenario is defined as "...a system state valid for a period of time, characterised by load and generation composition including the electrical topological state (breaker positions, etc.) and import/export to neighbouring areas".