INCORPORATING POWER MARKET SCENARIOS IN THE ADEQUACY ASSESSMENT OF THE NORWEGIAN POWER SYSTEM

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ABSTRACT

In reliability assessment of deregulated systems, the power market behaviour should be included in the analysis. A way of incorporating power market analysis in generation adequacy assessment is presented and discussed. It is shown that the price of electricity affect the load level, and thus the reliability level. Import/export capabilities are also shown to have an impact on the reliability level. The discussions and analysis focus on the Nordic power system.

***Index Terms*—** Deregulated power system, power market analysis, generation adequacy assessment.

1. INTRODUCTION

Adequate generation capacity is a basic requirement in power system planning and operation, where the adequacy assessment most commonly is done using probabilistic techniques [1]. A large system can be split into subsystems to carry out adequacy assessment per subsystem. This simplifies the analysis, and keeps the power generation facilities located in the same geographical area as the load.

Most of these probabilistic analysis techniques are developed for vertically integrated systems, where one central operator is responsible for the generation scheduling and system operation. In deregulated systems, this is no longer the situation, as different independent players participate in the power market and power generation. Therefore, in adequacy analysis of deregulated power systems, an analysis of the power market behaviour should be incorporated in the reliability assessment.

The Norwegian power system was deregulated in 1991, and during the 1990s a common Nordic electricity market (Nord Pool), including all the Nordic countries, was established. Nord Pool is responsible for the spot market and market clearing for the Nordic electricity market. Details regarding the organisation of the Nordic power market are found in [2, 3]. The Multi-area Power Market Simulator (EMPS) [4] is a popular tool for hydro power scheduling and price forecasting in hydro-thermal power systems, and will be used in the analysis of the Nordic power market.

The inclusion of the power market analysis, in the generation adequacy assessment, is done by using EMPS to find the load curves per area in Norway. These load curves will be used as a basis for the generation adequacy assessment, on a per area basis.

2. POWER MARKET ANALYSIS

EMPS is a stochastic power market model, with a stochastic time resolution of one week. The model is designed for medium-term and long-term analysis, with a future time horizon of 3-5 years. EMPS uses the water-value method to put a marginal cost on water stored in reservoirs, where the stochastic nature of hydro inflow is accounted for by using time series of historical weather data. Typically 50-75 years of weather data are included in the analysis.

Per week, for each modelled year, EMPS-NC (Network Constraints) [5, 6] finds the socio-economic optimal dispatch of the spot market, taking into account unit commitment cost and transmission constraints. EMPS-NC is an extension of EMPS, which use a linearized power flow to check the validity of each dispatch scenario.

EMPS-NC can find the weekly optimal dispatch on an hourly basis, or by splitting the week into different load periods. The load model in EMPS consists of a firm load, which is independent of the price, and a price sensitive part which in general increases as the price goes down. In this paper, each week is split into four different load periods, referred to as dispatch scenarios.

- Dispatch scenario 1: Mon-Fri, 12am-8am: Night-time during weekdays. This period covers 40 of the 168 hours in the week.

- Dispatch scenario 2: Mon-Fri, 8am-2pm: Morning on weekdays. This period covers 30 hours of the week.

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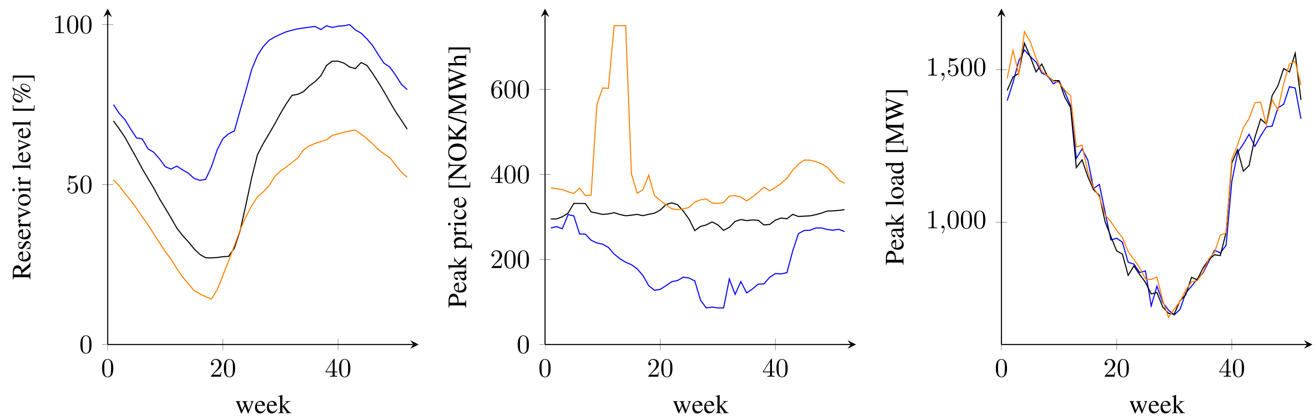

(a) Weekly average reservoir level

(b) Weekly peak price

(c) Weekly peak load

Fig. 1. Weekly values of average reservoir level, peak price, and peak load for a typical wet, dry, and normal year in Western Norway

- Dispatch scenario 3: Mon-Fri, 2pm-12am: Evening on weekdays. This period covers 40 hours of the week.
- Dispatch scenario 4: Sat-Sun, all day: Weekend.

For each dispatch scenario, the generation and load is given for each bus in the whole system.

3. GENERATION RELIABILITY ASSESSMENT

The generation reliability assessment is done on a per area (subsystem) basis. For each area and dispatch scenario, the area load is found by summation of the bus loads within the area.

For each area, the capacity outage probability table (COPT) is found considering the installed capacity for the given area. The COPT is updated according to maintenance schedules. The maintenance schedules are also included in the power market analysis.

The loss of load expectation (LOLE) and loss of energy expectation (LOEE) are used as risk indicators. For each dispatch scenario i, the LOLE is found per area as:

$$LOLE_i = \sum_{j \in C} I(L_i > P_{i,j}) \cdot p_j \cdot h_y \qquad (1)$$

where C denotes the set of all the capacity outage states in the COPT, $P_{i,j}$ is the available capacity of state j for dispatch scenario i, p_j the probability of state j, $I(\cdot)$ the indicator function, L_i the load for dispatch scenario i, and h_y the number of hours in one year.

As each dispatch scenario has a certain duration, the annual LOLE is found, per modelled year y, as:

$$LOLE_y = \sum_{i} LOLE_i \cdot \frac{h_i}{h_y} \qquad (2)$$

Table 1. Reliability Indices - Western Norway

Year	LOLE [h/year]	LOEE [MWh/year]
Dry	0.52	21.37
Normal	0.35	12.95
Wet	0.23	9.54

where h_i is the duration, in hours, of dispatch scenario i. The sum is over all dispatch scenarios within year y.

The same approach is used to find the annual LOEE per dispatch scenario and year.

These indices quantify the area risk, with respect to the area being self-sufficient with respect to generation resources. The dispatch given by EMPS often requires that a portion of the power consumed in one area is being produced in another area. The adequacy assessment presented here, does not take into account capacity assistance from other areas to supply the load in a given area. To include this in the analysis, a model describing available capacity in the surrounding areas is necessary.

4. RESULTS - WESTERN NORWAY

An area in the western part of Norway is analysed. In Fig. 1a, the weekly average reservoir level in the area is shown, for a typical dry, wet, and normal year. The hydro reservoir level peaks during the late summer weeks, and empties out during the winter, as most of the precipitation during the winter is snow in higher altitude. In late spring, snow melting cause water to flow into the reservoir again and it starts to fill up.

Figure 1b and Fig. 1c show the weekly peak price and peak load for the area. It is a clear correlation between reservoir level in Fig. 1a and price in Fig. 1b. From Fig. 1c, it

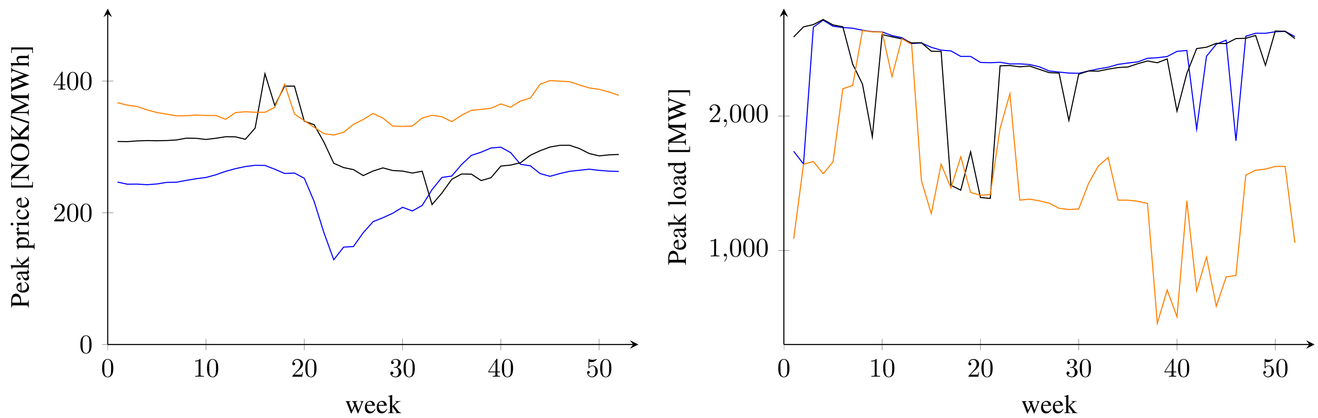

Fig. 3. Weekly values of peak price (left) and peak load (right) for a typical wet, dry, and normal year in southern Norway

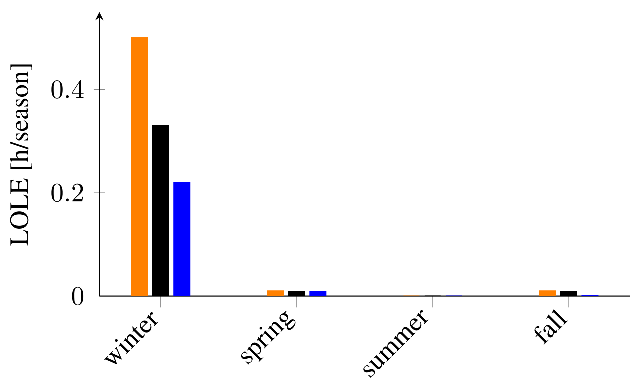

Fig. 2. The seasonal contribution to the LOLEs given in Table 1 for a typical wet, dry, and normal year. For instance, the sum of all the orange bars will give the LOLE for a dry year in Table 1.

is seen that the load is highest during the dry year. This is caused by the dry year also being a cold year, based on the historic weather data, while the wet year is fairly warm.

Based on the load curves in the Fig. 1, the annual LOLE and LOEE are found for the typical dry, wet, and normal year, where the values are shown in Table 1. Figure 2 shows the LOLE per season. The high load during the winter period causes a higher risk, and is the only period with a significant contribution the annual LOLE value.

5. RESULTS - SOUTHERN NORWAY

In southern Norway, there are HVDC cables connected to central Europe through Denmark and Netherlands. Here, the export (import) is included in the area load, which causes the area load to increase when power is exported and decrease if there is import.

In Fig. 3, the weekly peak price and peak load are plotted for a typical wet, dry, and average year. A low price causes the load to increase, as power is exported during this period. In case of high prices, the load is reduced due to import to the area. Comparing with the load curve in Fig. 1c, these areas have very different load curve characteristics.

Table 2. Reliability Indices - Southern Norway

Year	LOLE [h/year]	LOEE [MWh/year]
Dry	3.81	223.9
Normal	23.49	1638
Wet	28.80	1887

Based on the load curves in Fig. 3, the annual LOLE and LOEE are found for each example year, where the values are shown in Table 2. Figure 4 shows the LOLE per season. The indices are calculated assuming 100% reliable interconnections (HVDC cables), and generation failures in other areas are not considered.

6. DISCUSSION

In western Norway, the risk is higher in the dry years due to increased load, while in southern Norway, the risk is higher during wet years due to high export in this period. Thus, the risk is dependent on the type of year (wet/dry), and the system characteristics.

Due to the simple approach taken here, there are two important factors, which might affect the reliability level, which are not accounted for in the reliability assessment.

As the HVDC interconnections to central Europe are assumed 100% reliable, the power transferred over these lines have a load increasing/decreasing effect on the area load in southern Norway. However, outages of these interconnections will have a large effect on the power market, and thus on the reliability, and this should be included in the analysis.

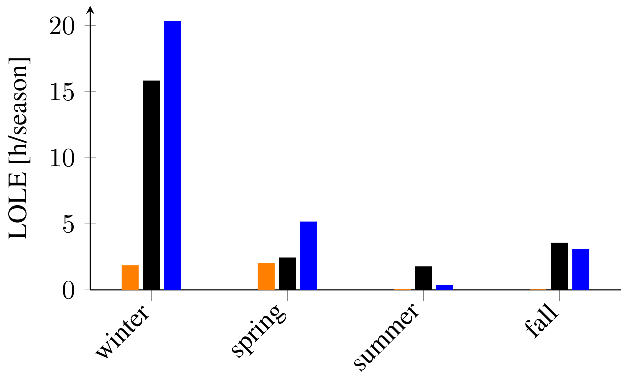

Fig. 4. The seasonal contribution to the LOLE's given in Table 2 for a typical wet, dry, and normal year. For instance, the sum of all the orange bars will give the LOLE for a dry year in Table 2.

The paper also does not incorporate a detailed analysis of the diurnal and seasonal variation of water discharge and head in the development of the hydro capacity model. This analysis should be considered in determining the capacity deratings of hydro power plants to improve the hydro capacity models for reliability evaluation.

7. CONCLUSION

A simple approach of including power market analysis in a reliability assessment is presented and discussed. It is shown that the price of electricity, and weather conditions, can drive the load up or down based on the characteristics of a certain area. The areas with high export capabilities through HVDC connections will increase export when the price is low, and increase import when the price is high, in the area.

The presented approach is very simple, and should be further refined by including reliability models for import/export, and consider cases where there are capacity deratings due to low reservoir levels.

8. REFERENCES

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