Probabilistic socio-economic cost assessment integrating power market and reliability analysis

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***Abstract*—Moving from deterministic to probabilistic reliability criteria for power systems necessitates probabilistic methods for socio-economic impact assessment. This paper demonstrates a probabilistic assessment of the long-term impact of the amount of transmission capacity given to the power market both on the market costs and on the expected customer interruption costs. A hydro-thermal market analysis is integrated with a contingency and reliability analysis and applied to the Nordic power system, focusing on a particular region of Norway and the transmission limits for this region. The results of this analysis are then combined in a socio-economic cost assessment that illustrates how a probabilistic approach and flexible transmission limits may allow for a more socio-economically optimal utilization of the grid. The results show that the impact of uncertainties (climatic variability) on the socio-economic cost assessment can be substantial.**

Keywords— power system reliability, security of supply, power markets, power system economics, net transfer capacity

I. Introduction

The reliability management of a power transmission system implies a sequence of reliability management decisions taken by the transmission system operator (TSO) [1]. These decisions aim at meeting a reliability criterion, which is used to determine whether or not the reliability level of a power system is acceptable. Reliability management practices have historically been deterministic, typically variations of the N-1 criterion [2]. However, from a socio-economic point of view, deterministic reliability management may lead to sub-optimal planning and operation of the power system. This is an important reason for the increasing interest, from TSOs as well as the research community, for moving from deterministic to more probabilistic reliability criteria that are better able to balance between reliability and costs. Among the drivers highlighted by TSOs is that more probabilistic reliability management approaches allow for more efficient grid use by giving more transmission capacity to the power market [2].

However, probabilistic reliability management necessitates probabilistic methods. This both includes methods for actually assessing the level of reliability and methods that are able to evaluate different reliability management approaches. Furthermore, methods need to be applicable to real systems and utilize the available data, and the availability of data is perceived as an important barrier against probabilistic reliability criteria [2]. Already decades ago it was pointed out how the lack of data have inhibited the use of advanced reliability assessment methods in practice [3].

The literature on probabilistic approaches to reliability management includes a few references on socio-economic cost assessment used to evaluate such approaches. Early work on this topic was presented in [4, 5], which included simplified estimates of both power market costs and expected customer interruption costs in the evaluation of a probabilistic security criterion. Later, a framework was developed for the trade-off between the costs and benefits of reliability from a socio-economic perspective [6]. Recently, [7] presented a detailed study of the costs and benefits of deterministic and probabilistic security criteria for the England–Scotland interconnector. As a part of the EU FP7 GARPUR project, a comprehensive methodology for socio-economic impact assessment has been developed [8] in the context of probabilistic reliability criteria. However, previous works on socio-economic cost assessment have in common that they 1) to a limited extent capture the market implications of maintaining a given reliability level, and 2) do not demonstrate the applicability of the methodologies for realistic or large system models.

The main contribution of the present work is an integrated methodology for socio-economic cost assessment integrating power market and reliability analysis and the demonstration of its application on a real system. More concretely, we consider as a case study the long-term impact of the amount of transmission capacity given to the power market (i.e. the impact of the transmission limits) on both the power market costs and on the expected customer interruption costs in a region of the Nordic power system. Aspects that are taken into account in this integrated analysis include 1) interactions between the power market and the power grid for a hydro-dominated power system such as the Nordic power system, 2) a long-term planning perspective considering a large number of representative operating states over multiple years, 3) uncertainties in terms of climatic variability (inflow, temperature-dependent load, wind), 4) a detailed grid model for a part of the Nordic power system, 5) time-dependent reliability data from the Norwegian fault and interruption statistics database (FASIT), and 6) time-dependent interruption costs as calculated in the Norwegian cost of energy not supplied (CENS) scheme.

The methodology presented in this paper conforms with the principles of the socio-economic cost assessment proposed in [8]. These principles have also been the basis of related research work [9, 10], primarily in the context of system

The research leading to these results has received funding from the European Union Seventh Framework Programme (FP7/2007-2013) under grant agreement No 608540, project acronym GARPUR.

DOI of published version: 10.1109/PMAPS.2018.8440342

operation (i.e. short term). These works are thus complemented by the present work, which takes a (long-term) system planning perspective. Our work is based on a previously developed methodology for reliability analysis integrating a market analysis [11, 12]. However, that methodology only partially considered the market–reliability interactions, and the implications of the reliability level on the power market has not previously been considered.

The rest of the paper is organized as follows: In Section II we present the methodology for integrated power market and reliability analysis and socio-economic cost assessment. The methodology is applied to a case study within the Nordic power system in Section III, considering the transmission limits to a particular region of the system. Some implications and limitations of the study are discussed in Section IV, after which the main conclusions are summarized in Section V.

II. METHODOLOGY

An overview of the key elements of the methodology for the integrated reliability and power market analysis is shown in Fig. 1: A power market analysis is carried out using a hydro-thermal power market model (module A), which generates representative operating states for the system and calculates the corresponding power market costs. As the Nordic power system is hydro dominated, hydrological (inflow) data for multiple years are essential inputs to the analysis to capture the climatic variability. Operating states and power market costs also depend on the transmission (or transfer) capacity available to the market, i.e. the transmission limits, that form constraints for the market clearing. A contingency analysis (module B) and a reliability analysis (module C) is then carried out for the operating states to estimate interruption costs. Module B also includes a preparation of operating states that includes clustering and a representation of special regulation. Finally, interruption costs are combined with the power market costs in a socio-economic cost assessment (D). In the following, each of the modules are briefly described. We also refer to [11, 12] for more information.

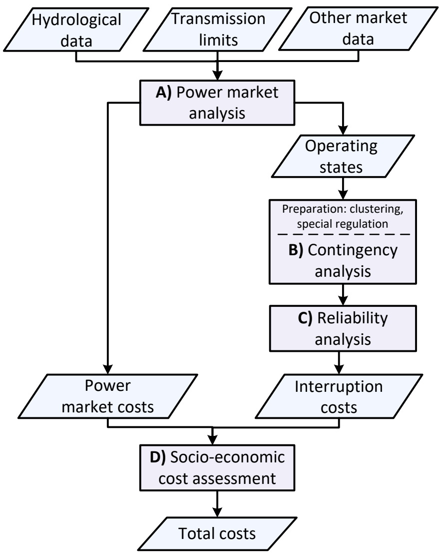

Fig. 1. Schematic of the methodology for socio-economic cost assessment integrating power market and reliability analysis.

A. Power market analysis

The power market analysis module used for this work is the Samnett power market model [13, 14]. Samnett is a variant of the EMPS model [15], which is a fundamental power market model that can be applied for long-term hydropower scheduling, price forecasting and general system studies.

The objective of the power market model is to minimize the expected sum of all system costs (here denoted the power market costs) over the operational planning horizon for a hydro-thermal power system. In this context, this corresponds to maximizing socio-economic surplus, i.e. the partial surplus from the power market, not taking into account possible contingencies. The power market surplus includes the total sum of producers and consumers surplus, the congestion rent, transmission losses, and the end value of water stored in hydropower reservoirs. The multi-period aspect is treated through a combination of water value computation by use of stochastic dynamic programming and simulation, governed by a heuristic layer.

Samnett builds on the EMPS model by integrating the market clearing with a detailed DC power flow study. The model utilizes aggregated power transfer distribution factors (PTDFs) between each area and each individual line, and adds linear constraints indicating which market areas (or price zones) that should adjust their net position in order to most economical efficiently alleviate the overload(s). A power grid equivalent is built for each base case power flow, in which each price area represents a node (bus). A user-defined weighting scheme is needed when aggregating PTDFs in the detailed transmission grid to an equivalent model. The explicit representation of the physical properties of the grid in the market clearing resembles the flow-based market clearing which is likely to be introduced in the Nordic power market in the future.

Among other things, the outputs of the market model include electricity prices per market area, demand per bus, and generation per generator. The market model also outputs the power market surplus and the power market costs. Transmission loss costs are included in production costs, as total generation equals consumption plus losses. Samnett estimates the transmission losses based on the DC power flow solutions and allocates these losses to the generators.

B. Contingency analysis

The outputs from the market model are given per climatic year, per week within each year, and per price segment within each week. The generation and demand for one such period for all buses in the system define an operating state, which is given as input to the contingency analysis module (module B in Fig. 1). To increase the computational efficiency of the integrated analysis, the number of operating states passed on to the contingency analysis is reduced using clustering methods. Based on the work in [16], we use agglomerate clustering of the net bus power injection data that represent each operating state to select a representative set of operating states. Operating states for each year are clustered separately, and which hours of the years the different operating states correspond to is tracked throughout the clustering process. Thus, the time dependence and correlations between different quantities can be captured also in results based on the clustered operating states.

When importing the operating states for the contingency analysis, one must take into account that the Samnett market model only requires the power flow to respect transmission limits between price areas or for specified power transfer corridors. This means that the operating states it outputs in general may have overloads for lines within each price area even before running the contingency analysis. These pre-contingency overloads are alleviated by adjusting the operating states by DC optimal power flow (OPF) calculations with interface flow constraints [17] ensuring that the adjusted operating states still respect the interface power flow given by the market model. The objective of this OPF problem is to minimize the deviation from the generator set points given by the market model. This preparation of the operating states resembles special regulation (re-dispatch) of generation as carried out by the TSO based on the results of the market clearing.

The contingency analysis module used for this work uses heuristics for modelling the system response to contingencies [19]. It can represent e.g. cascading tripping due to thermal overloads, islanding and changes in generation due to contingencies, and is based on MATPOWER [18] for AC or DC power flow calculations. The contingency analysis is run for each operating state provided by the market module and for each contingency in the contingency list defined by the user. The outputs it provides to the reliability analysis module are the power interrupted for each contingency for each delivery point and each operating state.

C. Reliability analysis

The reliability analysis module (module C in Fig. 1) is based on the OPAL methodology [20], which is an analytical reliability assessment methodology based on contingency enumeration and minimal cut sets. For each of the delivery points in the power system it calculates reliability indices including the expected number of interruptions per year, the annual expected interruption duration, and the expected average interruption duration and the expected annual energy not supplied. In addition, it calculates the expected annual interruption costs, i.e. the cost of energy not supplied (CENS), based on the CENS scheme that is implemented in Norway:

$$\mathrm{IC_a} = \sum_t \sum_k \sum_j \lambda_{t,j} r_{t,j} c_{t,k}(r_{t,j}) P_{\mathrm{interr},t,k,j} \,.$$

Here, $c(r)$ is the specific CENS for an interruption of equivalent duration r, λ is the equivalent fault rate, and P_{interr} is the interrupted power. The sums go over all operating states t in the year, all delivery points k and all minimal cut sets j. The methodology accounts for time dependencies of interruption cost data and reliability data. For further description and illustration of this functionality we refer to [21].

D. Socio-economic cost assessment

Finally, a socio-economic cost assessment is carried out by combining the results from the market analysis and the reliability analysis. The expected annual total cost is here defined as

$$\text{Total cost}_\mathrm{a} = \text{Power market costs}_\mathrm{a} + \mathrm{IC_a}.$$

Socio-economic impact assessment implies considering changes in the total cost. A change in total system costs is equal to a change in socio-economic surplus and can in our case therefore be expressed as follows:

$$\Delta\text{Total cost} = -(\Delta\text{Producer surplus} + \Delta\text{Consumer surplus} + \Delta\text{Congestion rent} - \Delta\text{Transmission losses} + \Delta\text{End value}) + \Delta\mathrm{IC}.$$

Socio-economic cost elements that are not considered in this implementation of the methodology include the cost of special regulation and the cost of changes or losses of generation during contingencies.

III. CASE STUDY

In this paper, the methodology described above is applied to a case study on assessing the long-term impact of changing transmission limits on both on the market costs and on the interruption costs. For the case study, we consider the interface of a particular region of the Norwegian power system, and increasing the transmission limit for this interface corresponds to decreasing reliability margins and increasing the share of the transmission capacity that is made available to the power market. We evaluate different values of the transmission limit through socio-economic cost assessment. This represents a more probabilistic and flexible approach than a transmission limit value chosen e.g. using a deterministic reliability criterion. Although the analysis focuses on the reliability of supply for one particular region, market and grid data for the entire Nordic power system are used to provide representative scenarios (operating states) for the power flow across the interface.

A. System model and data

The market model and the associated grid model represents the current Nordic power system and contains 1087 buses. The Norwegian power system is represented with higher degree of detail than the other countries belonging to the Nordic system and is divided in 15 price areas. Sweden, Denmark and Finland are divided in four, two and one price areas, respectively. Interconnectors between the Nordic power system and the Netherlands, Germany, Poland, Lithuania, Estonia and Russia are modelled as lines connecting to price areas with exogenous prices (given as time series). The market data set includes 30 historical (climatic) years (1981–2010) with both hydrological (inflow), temperature information. In addition to data on hydropower generators and thermal generators (the generation of which is modelled endogenously), the market data set includes exogenous wind power generation time series. Each week of the year is divided in 56 price segments of duration 3 hours each, giving a total of 2912 operating states per year.

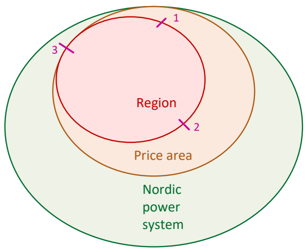

Fig. 2. Schematic illustration of the system, including the particular region and the interface lines (1–3) that are considered in the case study.

The case study focuses on one particular region within Norway which comprises 103 of the buses in the grid model. The region is generally a net importer of electric energy and is connected with the rest of the Norwegian power grid through three transmission lines (denoted interface lines 1, 2 and 3). This is illustrated schematically in Fig. 2, as the actual grid model cannot be illustrated due to the confidentiality of the data. The entire region lies within one of the price areas of the Norwegian power system. Interface line 3 crosses the boundary between this price area and another price area, whereas interface lines 1 and 2 do not cross any price area boundaries. For the case study, we focus on a pre-defined power transfer corridor in the market data set, namely interface lines 1 and 3. The transmission limit that is to be varied is thus defined in the market model as a restriction on the net power transfer over these two transmission lines combined.

The reliability data (fault rates and outage times) used for the case study are based on the Norwegian standardised system FASIT for collection, calculation and reporting of disturbance and reliability data [22]. FASIT has been in operation since 1995, and the data-base covers the entire medium- and high-voltage system in Norway and more than 20 years of data. Interruption cost data are based on the Norwegian CENS scheme. This scheme was introduced into Norwegian regulation in 2001 and is based on adjusting the grid companies' revenue caps in accordance with the customers' interruption costs [23].

B. Results

Fig. 3 shows the results of the power market analysis using the Samnett market model: The power market costs averaged over the entire 30-year period are plotted as a function of the transmission limits (i.e. the allowed net power transfer across interface lines 1 and 3). To assess the impact of changes in the transmission limits, the base case value is set to 400 MW, and results are plotted relative to this base case value. This base case value was chosen because it is a relatively restrictive limit for this particular case. Note that the socio-economic cost elements included in Fig. 3 do not include interruption costs.

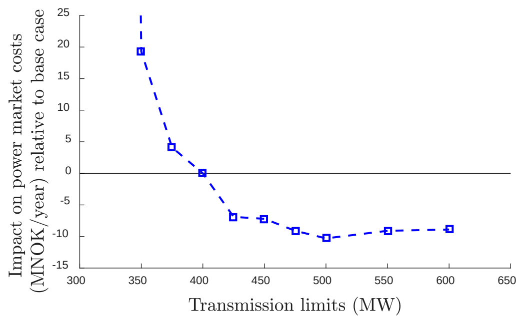

Fig. 3. Change in power market costs relative to base case (400 MW) for different values of the transmission limits.

As expected, the power market costs decrease as the transmission limits increase. Beyond transmission limits 500 MW the dependence of the power market costs on the transmission limits are not significant, and small changes shown in Fig. 3 are likely due numerical noise following from the use of heuristics in the market model. On the other hand, if transmission limits are reduced below 350 MW (not shown), the socio-economic costs increase steeply. In the following, the base case together with the transmission limit cases 350 MW, 500 MW and 600 MW will be considered to evaluate the impact on reliability of supply.

Operating states for each year were clustered using 100 clusters per year, resulting in 3000 clustered operating states to be analysed further for each transmission limit case. When using DC OPF to prepare the operating states for the contingency analysis as described in Sec. II.B, there were a small fraction of operating states (around 0.5 %, approximately the same for all transmission limit cases) for which no OPF solution existed. In other words, for the interface power flow constraints for the operating state given by the market analysis, there were no solution avoiding pre-contingency line overloads, given the line ratings of the grid model. These operating states therefore had to be discarded for the subsequent analysis.

In order to keep the computation time manageable for this case study, DC power flow was chosen for the contingency analysis. Although previous case studies have shown how DC power flow could lead to an overestimation of reliability [24], the system response modelling chosen for the contingency analysis is relatively conservative and could contribute to underestimating the reliability.

The results from the contingency analysis reflect that the region is not strictly N-1 secure, as N-1 contingencies do lead to power interruptions, but the extent of power interruptions varies greatly between operating states. This shows the value of assessing multiple operating states instead of simply assessing whether the system is N-1 secure for a single or a few operating states. The contingency list includes the 89 N-1 branch outage contingencies in the region. The outputs of the contingency analysis were then used in the reliability analysis to estimate expected annual customer interruption costs in the region. The results are presented in Fig. 4 as changes relative to the base case, averaged over all climatic years.

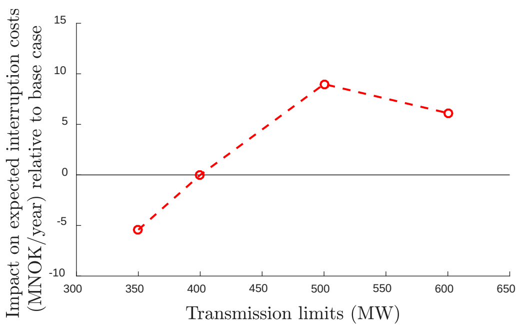

Fig. 4. Change in expected annual customer interruption costs relative to the base case for different values of the transmission limits.

The overall trend in Fig. 4 is that the interruption costs increase when increasing the transmission limits. However, the observed nonmonotonicity and the statistical uncertainties in the results will be discussed below. The same overall trend as shown in Fig. 4 was also found in other reliability indices such as energy not supplied and interruption frequency (not shown). Furthermore, the trend in the reliability indices was consistent across different delivery points. Outages of the three interface lines of the region were not major contributors to the interruption costs. In other words, for this particular case, the expected interruption costs and their trend were almost entirely determined by contingencies and resulting changes in power flow within the region.

Fig. 5 shows the results of the socio-economic cost assessment of changing transmission limits by combining the results from the reliability analysis and the market analysis. The purple curve shows the total cost, i.e. the sum of power market costs and interruption costs, relative to the base case. According to the results in Fig. 5, increasing the transmission limits leads to slightly lower total cost and hence a higher socio-economic surplus for this case, whereas decreasing transmission limits leads to significantly lower socio-economic surplus.

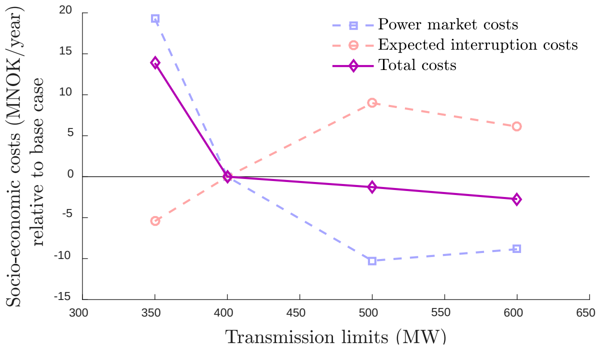

Fig. 5. Power market costs, expected interruption costs and total costs relative to base case for changes in the transmission limits.

Fig. 5 shows values averaged over the 30 climatic years considered in the analysis. For more insight into the variability and uncertainty associated with this socio-economic cost assessment, we consider the distribution of the two cost elements around these average values. Fig. 6 shows in the form of histograms for the 30 climatic years the changes in the socio-economic cost elements relative to the base case when changing the transmission limits. To estimate power market costs for each of the climatic years, deviations at the end of each year (referred to the beginning of the year) in aggregate reservoir levels are valuated according to the pre-calculated water values.

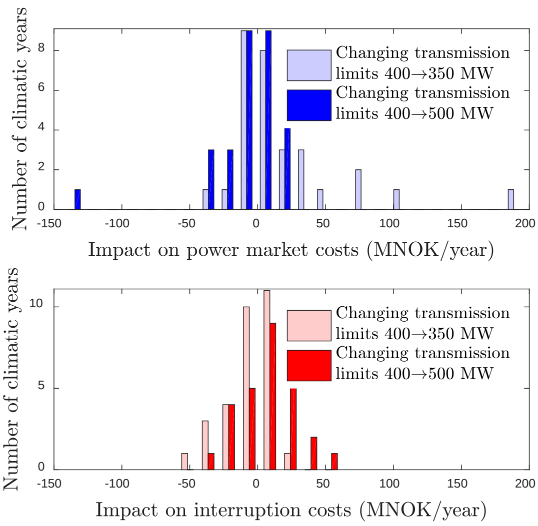

Fig. 6. Histograms of the change in the socio-economic cost elements (annual power market costs above and annual expected interruption costs below) when changing the transmission limits.

It can be seen from Fig. 6 that when increasing the transmission limits, the distribution for the power market costs is shifted to the left (dark blue), indicating a negative impact on the power market costs. Correspondingly, increasing the transmission limits shifts the distribution of the interruption costs to the right (dark red), indicating a positive impact on the interruption costs. Comparing the upper and lower parts of Fig. 6, one can observe that there are some years that contribute to a large share of the expected impact of changing the transmission limits on the power market costs, and this is not to the same extent the case for the interruption costs. Nevertheless, for this case, the width of the distributions is in the same order of magnitude for both cost elements.

However, for both socio-economic cost elements there are climatic years for which the impact of changing transmission limits is in the opposite direction from the overall trend described above. Furthermore, for both cost elements the width of the distributions is large compared to the average shift of the distributions for changing transmission limits. Fig. 6 therefore demonstrates that the impact of climatic variability on a long-term reliability and socio-economic cost assessment can be substantial. For Fig. 4 and Fig. 5, this means that one cannot conclude that the nonmonotonicities observed in the results are statistically significant. More generally, it implies that it is important to consider the uncertainties associated with the climatic conditions expected over the planning horizon.

IV. Discussion

The methodology used for this case study captures the trade-off between power market costs and the reliability of supply when changing transmission limits. The impacts of changing transmission limits are case dependent and may depend both on a) the specifics of the region and b) the selection of the transmission lines for which the transmission limits are enforced. It has also been found for this case that the representation of special regulation was important to capture the impact on the reliability of supply. However, in the current implementation of the methodology, the net re-dispatch cost is not explicitly quantified. If this cost element changes significantly for changes in the transmission limits, this could also influence the results of the socio-economic cost assessment.

Furthermore, the methodology allows for utilizing available data, such as time-dependent reliability and interruption cost data, and detailed market data. Especially for an integrated power market and reliability analysis, it is important to ensure consistency between the data used in different modules of the analysis. For instance, we use the same grid description in all the modules, and this allows for considering operating states in the contingency analysis that are consistent with the assumptions made in the market analysis. Integrating the reliability analysis with a market analysis is also particularly relevant when assessing the socio-economic impact (including impact on reliability of supply) of future system development scenarios or possible changes is the market design.

The presented methodology and case study has a planning perspective and employed a simple representation of short term system operation within the long-term reliability assessment. Viewed in a short-term perspective, it would be relevant to consider time-dependent transmission limits that are changed based on e.g. weather and market forecasts for each day. Accurate reliability assessment is crucial for providing TSOs with decision support, and reliability assessment for short-term reliability management purposes is a possible extension of our work. More flexible and socio-economic optimal operation of the power system would also impact the socio-economics viewed in a long-term perspective.

V. CONCLUSIONS

In this paper, an integrated methodology for reliability and power market analysis has been demonstrated through a case study with realistic data for the Nordic power system. It is shown how one can, utilizing available data, evaluate both a) the impact of the power market on the reliability of supply, and b) the impact of reliability management decisions (here: changing transmission limits) on the power market costs. Moreover, it is shown how both these aspects can be combined in a socio-economic cost assessment.

The results presented from this case study illustrate how a probabilistic approach and flexible transmission limits could possibly allow for a more socio-economically optimal utilization of the grid, supporting the principles of more probabilistic reliability management approaches. The results also demonstrate that the impact of climatic variability and uncertainties on such analyses can be substantial. When estimating the long-term expected interruption costs and socio-economic impact it is therefore important to capture a large number of operating states and include climatic data for a large number of years.

The case study also demonstrates the applicability, for a real system and with available data, of such a probabilistic socio-economic cost assessment. It also illustrates the value of additional data, in line with e.g. the recommendations from the GARPUR project [25], including systematic collection and sharing of reliability and interruption cost data, and sharing of realistic grid and market data sets.

ACKNOWLEDGMENT

The authors would like to thank Oddbjørn Gjerde, Sigurd Hofsmo Jakobsen, Til Kristian Vrana and Espen Hafstad Solvang for their contributions to this work and partners of the GARPUR project for useful input and feedback. The Norwegian Water Resources and Energy Directorate are acknowledged for providing the market and grid data.

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