Importance and Difficulties of Comparing Reliability Criteria and the Assessment of Reliability

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***Abstract*—Due to the importance of reliable electricity supply and the evolutions in the electrical grid, it can be expected that the way in which we assess reliability need to be adapted. At this moment, reliability is commonly assessed deterministically based on an N-1 criterion, while risk-based reliability assessment is widely available in academic works and is used in other industries. However, because of the years of successful use as well as the straightforward and transparent character of the currently used deterministic approach based on an N-1 criterion, stakeholders of the power system are not eager to apply other approaches. Nevertheless, probabilistic assessment is better suited to take into account growing uncertainty and complexity, for instance due to the increased amount of renewable energy sources. Such approaches are well-known for a long time, but difficulties in computation, limitations on the availability of stochastic input data and difficulties in correctly weighing the benefits of using these approaches have prevented them from being used in practice. This paper indicates the need for a comparison between these probabilistic reliability assessments and the deterministic assessment that is currently used. Difficulties in comparing various approaches are shown illustratively through the reliability assessment of a basic test system. The focus of this example is on planning.**

I. Introduction

Reliability of electricity supply plays a major role in the economics and social well-being of a modern society and directly influences the quality of life. A one day blackout could lead to costs that are about 0.5% of the GDP of a country, which have to be added with possible social consequences such as diseases, deaths and injuries [1]. The effect on consumers, especially industry, can be such that the reliability of the local energy provision is key to the selection of a site, e.g. Google that is located in Bergen (Belgium). Therefore, the power system can be seen as one of the most critical infrastructures these days and a correct assessment and adequate level of the reliability is of utmost importance.

The power system is also one of the most complex man-made systems in the world, which is continuously evolving. Some evolutions of the last decades are the increasing degree of interconnection, deregulation, privatization and unbundling. On the other hand, currently used reliability models were conceived with a centrally planned and operated nature of generation, transmission and distribution in mind [2]. Restructuring to enable European wide competition has led to increasing awareness of cost effectiveness and changing concerns of different stakeholders. Utilities also accept higher risks due to competition [3]. Moreover, increasing generation of renewable energy sources in the system has led to higher uncertainties, which under N-1 criteria, or an adapted formulation of the N-1 criteria, require larger reliability margins and hence lead to a system that is used in a less cost-effective manner. The increasing use of power electronics challenges the reliability of the system and the application of the currently used reliability criteria even more. Furthermore, reports show that major disturbances occur due to combinations of failures not dealt with in the currently used deterministic approach based on an N-1 criterion, as it deems them as not probable [4]–[6]. Consequently, the implementation of new probabilistic reliability criteria needs to be considered [7].

McCalley and his associates demonstrate the shortcomings of an N-1 criterion by comparing with a risk based approach using a predefined contingency list [8]. Kirschen et al. further elaborate on this by using Monte Carlo simulation techniques considering all contingencies [9]. Outweighing both approaches is difficult because accuracy and computational burden need to be balanced. Benefits of using one approach compared to the other are not quantified yet. On the other hand, Guler et al. propose an approach for the assessment of market performance under a specified reliability criterion and its reliability management framework. This entails a quantification of the monetary impact of applying an N-1 criterion under various reliability management frameworks using a security constrained optimal power flow (SCOPF), however, without taking into account probabilities [10]. It is important to mention that in all methodologies, data availability and accuracy is of utmost importance. Specifically the availability of stochastic input data limits the use of probabilistic methods.

This paper elaborates on the importance of comparing reliability criteria and the assessment of reliability focussing on arising difficulties in comparing the impact of applying various reliability criteria. Firstly, section II clarifies various terms used in this paper concerning reliability. Section III deals with the importance of comparing reliability criteria by firstly introducing the currently known criteria and approaches complemented with their shortcomings. In section IV, different reliability criteria and the assessment of reliability are compared using a small test system and arising difficulties are presented. Finally, section V concludes the paper.

The research leading to these results has received funding from the European Union Seventh Framework Programme (FP7/2007-2013) under grant agreement No 608540 Garpur project http://www.garpur-project.eu
KU Leuven is a founding member of EnergyVille

II. Definitions and concepts

Power system reliability means the probability that an electric power system can perform a required function under given conditions for a given time interval [11]. Thus reliability quantifies the ability of a power system to provide an adequate supply of electrical energy in order to satisfy the customer requirements with few interruptions over an extended period of time. It can be divided into power system security and power system adequacy [12].

The aim of a high power system reliability is a low frequency of inability to serve load with the required quality and a very low frequency of experiencing spectacular system failures such as blackouts [13]. To ensure an adequate level of reliability while minimizing socio-economic costs, power system reliability management is applied, which is composed of two main tasks: i) reliability assessment and ii) reliability control.

Reliability assessment aims at identifying the actual reliability level. An acceptable reliability level is set by a reliability criterion, which can be expressed as a set of constraints that must be satisfied. Criteria mainly used these days are derived from the deterministic N-1 approach, which states that the system should be able to withstand at all times the loss of any one of its main elements (lines, transformers, generators, etc.) without significant degradation of service quality. Similarly, generation adequacy can for instance be ensured by generation reserves that must be equivalent to the capacity of the largest unit on the system plus a fixed percentage of the dispatched capacity [14]. New reliability criteria based on other (probabilistic) reliability indicators might improve reliability. The suitability of various reliability indicators depends on the hierarchical level they are applied to, i.e. generation, generation and transmission or the combination of generation, transmission and distribution. Typical reliability indicators used in power system adequacy evaluation are energy not served, frequency and duration indicators, loss of load probability,... They indicate the probability, severity, frequency and duration of loss of load [14]. These reliability indicators can either be system indicators or load point indicators, which represent the reliability of respectively the whole system or individual load points. This paper focuses on generation and transmission and calculates reliability indicators at busbars at which large customers and distribution system operators (DSOs) are connected.

Reliability assessment methods allow to verify whether reliability criteria are satisfied and to quantify the reliability level of the system using reliability indicators. Two main reliability assessment methods for a probabilistic reliability assessment are the analytical contingency enumeration method and the simulation method (e.g. Monte Carlo) [7]. System security can be evaluated using a probabilistic security assessment, transient stability assessment, dynamic security assessment,... The deterministic approach currently used in practice applies state enumeration and checks for a predefined set of N-1 contingencies whether limits on system variables are violated.

Reliability control entails taking preventive and corrective actions in order to satisfy the applied reliability criterion [15] and avoid unacceptable deficits of electricity supply. Preventive actions are pre-contingency modifications to the power system that are taken to satisfy the reliability requirements and to prevent a transition to an emergency state. Corrective actions are post contingency actions and taken when the system is in an alert or emergency state, to correct the system behavior in order to recover to the normal state. Possible actions are generation redispatch, adjustment of reactive control variables or load shedding [16]. An emergency state sometimes requires an emergency plan to recover the system. An overview of the different system states and respective kinds of control actions is shown in figure 1. Next to short term control actions, decisions on system development and asset management are important to control the reliability level of the system [17].

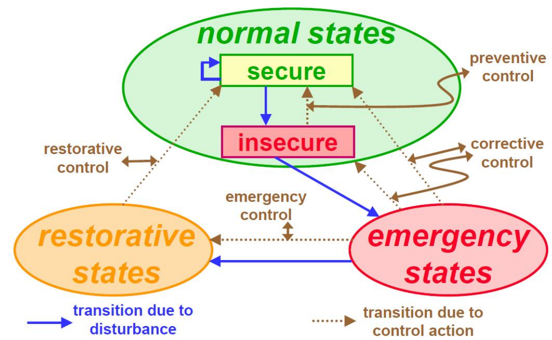

Fig. 1. Overview of reliability control by using preventive, corrective or restorative control depending on the state of the system [10]

III. Importance of comparing reliability criteria and the assessment of reliability

Based on the state of the art of the development as well as experiences of the application of various types of reliability assessment and criteria, the need for comparing reliability criteria can be derived.

A. *Types of reliability criteria*

In order to obtain sufficient reliability in the power system, redundancy in the grid will be needed, but a clear risk for over-investments or restriction of the market exists. Reliability criteria should guarantee an appropriate reliability level of the power system, which balances these economic and reliability considerations.

The first reliability assessments used in practical applications and still used nowadays all have a common deterministic nature, but the effective criteria differ for different time horizons of power system exploitation, namely system development (long term), operational planning and asset management (medium term) and operation (short term) [18], which are interlinked. The focus of this work is on planning. Network capacity planning is mainly based on an N-1 criterion. This is satisfied by constructing a minimal number of circuits to a load group. The minimal number of circuits depends on the maximal demand of the group [18]. N-1 criteria, however, have various shortcomings [1], [7], [9], [13], [19], [20]:

- It is important to note that although an N-1 criterion is straightforward, transparent and widely used, it in itself can be interpreted in many ways. In practice, neither the number of elements to be considered (N) nor the type of contingencies considered (-1) is dealt with equally amongst TSOs and even within a single organization.

- They suppose that different contingencies are equally severe and that they occur equally likely.
- They do not give an incentive based on economic principles, because they do not take outage costs into account.
- All grid elements are assumed equally important and all generators and consumers have equal weight.
- They do not consider the stochastic nature of failures of grid components, generation and demand, the interdependencies between different events or the interaction between the frequency of the contingencies and the exposure time to high stress conditions.
- They are binary criteria: the system is either reliable or not reliable. Therefore, an accurate reliability level cannot be obtained, which results in over or under-investments.
- They only take into account single contingencies. Single contingencies are much more probable than double contingencies if outages are independent events, but hidden failures in the protection system can trigger additional outages cascaded to the original fault. Furthermore, due to significant increase of the rate of outages during bad weather conditions, the probability of two quasi simultaneous but independent outages is no longer negligible.

Nevertheless, N-1 criteria, or adapted formulations of the N-1 criterion, are extensively used nowadays due to various reasons. Firstly, they could be used at any time, because the predictability and controllability by the grid operator of the operating environment of the electric power system was sufficiently high until recently. Secondly, interconnections initially aimed at mutualizing some risks in terms of short term adequacy, while keeping cross border flows limited. N-1 criteria could be easily satisfied due to the conservative design of the interconnections at the initial stage, but this could lead to non-optimal solutions. This is in contrast with the current use, because cross-border power flows increase significantly due to the development of the European Electricity market, which requires more coordination over a wider area. Thirdly, the deterministic N-1 approach is easy to understand, transparent and straightforward to implement in contrast to the complexity of implementing probabilistic approaches [21].

However, many probabilistic aspects are inherent to the power system due to internal and external events. Firstly, demand is fluctuating over time, so uncertainties exist in the forecasts. Next to that, renewable energy sources, such as solar energy and wind energy strongly depend on the weather conditions, so generation schedules are influenced by weather forecasts as well as by market behavior, which is also uncertain and influenced by renewable energy sources as well. Events occur randomly, uncontrolled vegetation can lead to sudden short circuits with overhead lines, power system components can fail in an unpredictable manner,... Furthermore, the system is used closer to its limits and more complex solutions are used due to the low social acceptance of overhead lines [7].

A lot of research is already done on development and application of new approaches incorporating these probabilistic effects in reliability analysis [22]. Probabilistic approaches are already used in reliability calculations for power system planning and development, for instance to determine the generation reserve in the system development phase, but transmission system operators (TSOs) apply them rarely in the operational time frame [9]. Some countries that use probabilistic reliability criteria for planning are Australia [7], New Zealand [7] and the province of British Columbia in Canada [20]. The limited use of probabilistic approaches is among others due to the transparency, straightforward characteristics, lower computational burden and the acceptable level of reliability that results from deterministic criteria but on the other hand, this results also from data limitations and the lack of quantified benefits of using probabilistic approaches.

B. Reasons for comparison

Probabilistic approaches have the ability to overcome many of the shortcomings related to a deterministic N-1 approach and to tackle issues that come with evolutions of the power system. Also literature points out the importance of the evolution towards probabilistic approaches [7], [17], [19].

In order to convince stakeholders to implement new reliability criteria, a thorough evaluation and comparison of these new reliability criteria with currently used N-1 criteria is needed. This comparison needs to take into account reliability aspects as well as economic aspects. It allows to quantify benefits of implementing other reliability criteria that simplify making economically justified investments in the power system or taking appropriate operational action, which will improve reliability and social welfare[1] in the next decades.

Furthermore, the comparison of probabilistic indicators with the currently used N-1 criterion allows the determination of appropriate thresholds of the probabilistic indicators. These can be used as reliability criteria that can take reliability as well as economic aspects into account, which will contribute to a cost effective increase of reliability.

IV. Comparing reliability criteria and the assessment of reliability

Comparing the performance of various reliability criteria is a difficult task. A set of difficulties is demonstrated using a reliability test system on which the impact of system development decisions could be assessed.

A. Methodology

The reliability of the basic test system shown in figure 2, which is based on the Roy Billinton Reliability test system [23], is assessed using Matlab and the MATPOWER tool [24]. In order to investigate the influence of adaptations to the system on reliability indicators, four different cases are considered as given in figure 2.

Failure times of the branches are assumed to be exponentially distributed [18], so failure rates (λ) are constant and are

[1] In this paper, social welfare is defined as the sum of consumer and generator surplus as economic indicator

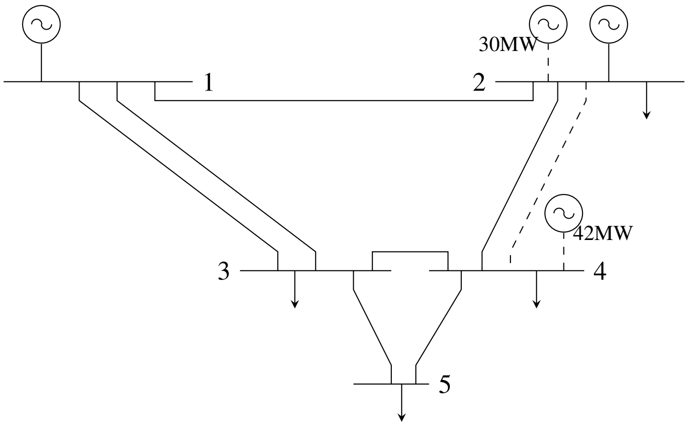

Fig. 2. Used reliability test system [23]. Four cases are considered. Case 1 is the system without the dashed elements, i.e. the base case, case 2 is case 1 with 30MW extra non-variable generation installed at node 2, case 3 is case 2 with an extra line between node 2 and 4 and case 4 is case 2 with 42MW non-variable generation installed at node 4.

summarized in table I [23]. Based on these failure rates and a constant repair time of 10 hours, the probability of failure of the various branches can be calculated. S_{limit} corresponds to the thermal limit of the lines.

TABLE I. SUMMARY OF IMPORTANT DATA OF THE TEST SYSTEM [23]

Branches	λ [year^{-1}]	Probability of failure	S_{limit} [MVA]
1-2	4	0.004568	71
1-3	1.5	0.001713	85
2-4	5	0.005710	71
3-4	1	0.001142	71
3-5	1	0.001142	71
4-5	1	0.001142	71
Nodes	$E[P_{g,2}]$ (σ) [MW] Case 1	Case 2,3,4	Maximum load [MW]
1	80 (+/-0)	80 (+/-0)	0
2	90 (+/-5)	130 (+/-5)	21.3
3	0	0	90.5
4	0	0	42.6
5	0	0	10.6

The reliability of the test system is assessed as a function of two system variables, namely total load (P_d) and generation capacity at node 2 ($P_{g,2}$). Generation capacity at the first node is fixed, while generation capacity at the second node is normally distributed with average value ($E[P_{g,2}]$) and standard deviation (σ) depending on the considered case, as indicated in table I. The annual load distribution is calculated based on values in [23]. Generation capacity and load are considered as independent variables and form a domain $\mathcal{X} \triangleq \{\mathbf{x} = [x_1 \ x_2] : x_1 \in [P_{d,min}..P_{d,max}], x_2 \in [P_{g,2,min}..P_{g,2,max}]\}$ with $\mathbf{x}$ a particular combination of values of the system variables, i.e. x_1 corresponds to P_d and x_2 to $P_{g,2}$. $P_{d,min}$, $P_{d,max}$, $P_{g,2,min}$ and $P_{g,2,max}$ are the limits of the domain consisting of load and generation capacity at node 2.

The probabilistic reliability assessment applied in this paper uses the analytical method of contingency enumeration. The contingency list contains contingencies up to two branch outages. The reliability is assessed for all contingency cases on the contingency list, for every **x**, i.e. a particular combination of values of the system variables. Violations of branch flow limits and voltage limits are relieved using corrective actions, namely generation redispatch and load shedding. Three probabilistic reliability indicators, i.e. the interruption duration, the energy not served and the outage costs, quantify the reliability level of the system if a certain reliability criterion with its respective reliability management is applied.

Interruption duration is based on the restoration time of load shed, which consists of two parts: control time and true restoration time [25]. The control time is defined as $ID_{control} = 30\frac{P_S}{P_{Tot}}$ [min], with P_S the load shed and P_{Tot} the total load that would need to be supplied. The restoration rate after this control period depends on the duration of the interruption for which four time intervals are defined in [25]. Annualized expected interruption duration for one combination of values of the system variables $ID(\mathbf{x})$ is given by [18]:

$$ID(\mathbf{x}) = \sum_{i=1}^{I} ID_i(P_{S,i}(\mathbf{x})) \times F_i \tag{1}$$

F_i is the number of appearances of contingency case i per year, $ID_i(P_{S,i}(\mathbf{x}))$ is the interruption duration based on the heuristic for restoration times in [25] with $P_{S,i}(\mathbf{x})$ the load shed, both for contingency case i.

Annualized expected energy not served for a particular combination of values of the system variables $ENS(\mathbf{x})$ can be calculated using equation 2 [18].

$$ENS(\mathbf{x}) = \sum_{i=1}^{I} P_{S,i}(\mathbf{x}) \times ID_i(P_{S,i}(\mathbf{x})) \times F_i \tag{2}$$

Finally, annualized expected outage costs can be calculated using value of lost load (VOLL), which are costs in [€/kWh] caused by the interruption of energy. VOLL for a typical bus as given by Kirschen et al. [25] is used for all nodes. These values are converted to € using a conversion factor of 1.22€/£. VOLL is in principal a non linear function of duration, location and time and subject to debate. In the same way as the interruption duration, annualized expected outage costs for a particular combination of values of the system variables $OC(\mathbf{x})$ can be calculated [25]:

$$OC(\mathbf{x}) = \sum_{i=1}^{I} OC_i(\mathbf{x}) \times F_i \tag{3}$$

with $OC_i(\mathbf{x})$ the outage cost for contingency case i calculated using $\sum_{j=1}^{n}(\text{VOLL}(t_j) \times t_j \times P_{S,i,j}(\mathbf{x}))$. In this equation, t_j is the outage time for load segment j computed from the load restoration process, $P_{S,i,j}(\mathbf{x})$ is the reconnected load corresponding to segment j and $\text{VOLL}(t_j)$ is the value of lost load as stated in [25] as a function of the outage time.

By complementing these annualized indicator values with probabilities of occurrence of various combinations of values of the system variables, expected annual values of the reliability indicators ERI can be calculated as follows:

$$ERI = \int\int_{\mathcal{X}} RI(\mathbf{x})p(\mathbf{x})dx_1dx_2 \tag{4}$$

$$\approx \sum_{x_1}\sum_{x_2} RI(\mathbf{x})p(\mathbf{x})\Delta x_1 \Delta x_2 \tag{5}$$

with RI(**x**) the annualized expected value of the reliability indicator (e.g. ID(**x**), ENS(**x**), OC(**x**)), $p(\mathbf{x})$ the probability of operating in state $\mathbf{x}$, a particular combination of values of the system variables, and Δx_1 and Δx_2 the discrete intervals between the considered values of the system variables.

B. Discussion of the results

Figure 3 shows the operational region of case 1 in terms of total load and generation capacity at node 2, complemented with the operational limits of the N-0 and N-1 criteria and an iso-risk curve in terms of ENS. The figure shows that operating corresponding to the N-0 or N-1 criterion does not imply a constant risk level. The N-0 limit exists due to the possibility of lack of generation capacity in combination with higher loads. Although probabilities for N-0 unsafe conditions are smaller than 0.0011, action is needed in order to satisfy the criterion. Investments in non-variable generation at node 2 could solve this issue (case 2). Furthermore, part of the operational region lies within the unsafe N-1 region.

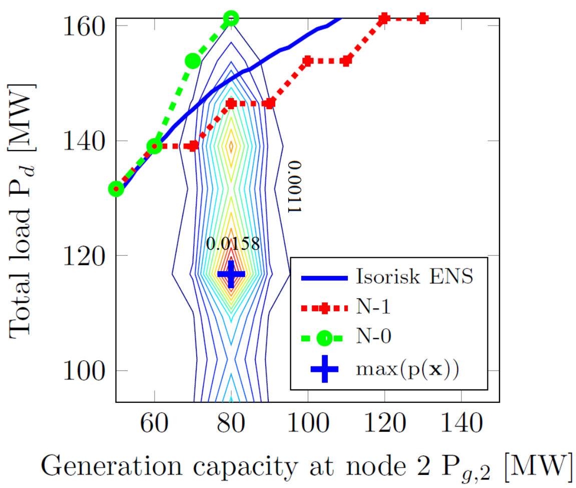

Fig. 3. Operational region of case 1 in terms of total load and generation capacity at node 2. Probabilities of the operational points are given by the contour plot. Values corresponding to the outer contour and maximum probability are indicated. The dashed and dotted lines represent respectively the N-0 and N-1 operational limits, while the bold full line shows an iso-risk curve in terms of ENS.

Satisfying different reliability criteria requires actions, but the N-1 reliability criterion does not indicate which action is preferable. It only indicates which ones are acceptable and those that are not. Table II shows the influence on the probabilistic reliability indicators of different reinforcement decisions to make case 2 N-1 safe. Values of the reliability indicators in case 3 and 4 are expressed as a percentage of the values in case 2. Based on various probabilistic reliability indicators, different solutions could be put forward. An extra line (case 3) outperforms in terms of expected interruption duration, while you would opt for extra generation at node 4 (case 4) based on expected energy not served and outage costs. If no unambiguous metric is defined, it is hard to compare the impact of the application of various reliability criteria.

Cost effectiveness of reinforcements strongly depends on the used contingency list. Figure 4 shows differences in dynamic pay back period (DPBP)[2] of an investment in an extra line 2-4 using either a contingency list consisting of all single branch outages or one taking into account up to two branch outages. The assumed investment cost equals €1000000 /km. Figure 4 shows that the investment looks much less interesting in terms of dynamic pay back period if only single branch outages are considered, while DPBP decreases a lot if two simultaneous branch outages are considered as well.

[2]The dynamic pay back period (DPBP) takes into account the discount rate and is defined as the year in which the net present value becomes positive.

TABLE II. RELATIVE RELIABILITY INDICATORS TO EVALUATE POSSIBLE REINFORCEMENT SCHEMES OF CASE 2

Indicators	Case 2 [1]	Case 3 [1]	Case 4 [1]
Expected interruption duration (EID) [%]	100	**3.14**	5.05
Expected energy not served (EENS) [%]	100	2.24	**1.73**
Expected outage costs (EOC) [%]	100	3.10	**2.99**

[1] Description of cases given in figure 2

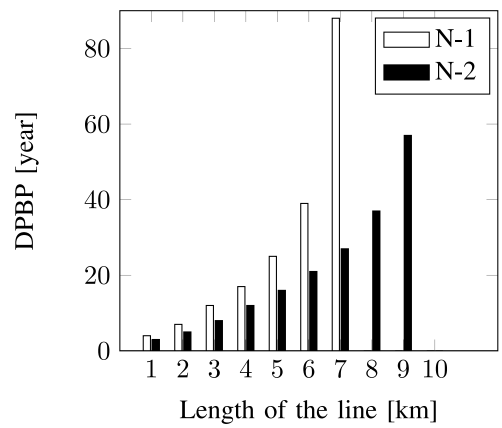

Fig. 4. Dynamic pay back period of an investment in an extra line 2-4 using two different contingency lists taking into account either single branch outages (N-1) or up to two simultaneous branch outages (N-2) as a function of the length of the line

C. Difficulties in comparing reliability criteria and the assessment of reliability

Based on the reliability assessment of previous section and from literature [8], [9], we observe that various difficulties are encountered while comparing reliability criteria. Firstly, various reliability criteria are based on different reliability assessment approaches, each with their own fundamental mathematical methodologies. The probabilistic reliability indicators in this paper are calculated using an analytical contingency enumeration method. In theory, all possible contingencies, including all combination of single contingencies, need to be in the contingency list. This will lead to a very high computational burden, especially in large complex systems. Furthermore, because probabilistic approaches need extra input data compared to deterministic ones, more variations are possible in terms of assumptions and simplifications. These input data can be based on forecasts or historical statistics and are therefore less accurate. Moreover, the analysis in this paper only considers the variation of two system variables, while in practice the system consist of many more system variables and control variables. These variables are not necessarily independent and correlation with weather data needs to be taken into account. The reliability level resulting from probabilistic approaches will therefore strongly depend on the assumptions and simplifications made and the used assessment method. This balance between accuracy and computational burden and the strong influence of assumptions on the results hamper the comparison of the impact of the application of various reliability criteria.

Deterministic approaches based on an N-1 criterion on the other hand have a very straightforward contingency list, namely the outage of one of all components at a time, and do not take into account probabilities, which diminishes variation in results. These criteria indicate whether action is needed, but based on various reliability indicators, different best options exist. Furthermore, nowadays no practical meaning is assigned to numerical values of the probabilistic indicators.

Further research has to focus on the development of an appropriate methodology to compare the performance of various reliability criteria and its respective reliability management using an unambiguous metric. Social welfare seems to be the most appropriate proposal for this. This would imply a regulatory framework that enables or gives incentives to all stakeholders to operate their system in a manner that maximizes social welfare. However, not all needed data for social welfare evaluation are available to the relevant stakeholders, specifically the system operator. Therefore, a suitable approximation for social welfare needs to be developed, which entails costs of energy not served for the customers as well as costs resulting from reliability decisions in the framework of reliability management incurred by TSOs. Including various uncertainties of the system in this methodology will be a challenge.

V. Conclusion

Deterministic reliability assessment is used successfully for many years. However, due to evolutions in the power system and various shortcomings of deterministic criteria (most specifically N-1), other reliability assessment approaches need to be considered. Other approaches are already developed, but they are rarely used in practice and their benefits are not well quantified. Nevertheless, they are important as decisions are based on them. Therefore, comparing reliability criteria and the assessment of reliability is important. This is a difficult task due to the different mathematical nature of various kinds of reliability assessments. Furthermore, deterministic assessments based on an N-0 or N-1 criterion indicate appropriate actions, but not the best option, while outcomes of probabilistic assessments strongly depend on the assumptions made and the balance between accuracy and computational burden. Furthermore, lack of an appropriate metric to indicate the benefits of applying one reliability criterion rather than another hampers the comparison. This paper has illustrated the above for transmission system planning in a system based on the Roy Billinton Reliability test system. It shows that different reliability indicators and criteria can lead to different decisions in systems under uncertainty.

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