NEW HYBRID PLANNING APPROACH FOR DISTRIBUTION GRIDS WITH A HIGH PENETRATION OF RES

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ABSTRACT

The new hybrid approach for distribution grid planning presented in this paper combines a probabilistic load flow calculation with a deterministic contingency analysis. Thus, in this hybrid approach the maximum loading of each system line is obtained from the probabilistic load flow calculation, and then the contingency analysis is applied to those scenarios. Furthermore, the probabilistic load flow shows that the predefined deterministic scenarios – as used in the present-day approach – do not accurately represent the line loading. Thus, calculation of the necessary grid reinforcements in the contingency analysis can lead to sub-optimally dimensioned grids when using the present-day planning approach. The application of the proposed new hybrid planning approach can improve estimation of required transport capacity significantly.

INTRODUCTION

Both the number and the installed capacity of renewable energy sources (RES) has grown rapidly in recent years, especially in Germany. This has resulted in reverse power flow conditions, meaning that power flows from the distribution grid up to the transmission grid. Historically, distribution grids were planned based on demand considerations to ensure a reliable delivery of energy to end-users [1]. When there are high concentrations of volatile distributed generation (DG), the generation units interacts with each other and with the loads in the grids [1]. Hence, the necessary reinforcement of the electric grid, calculated with the methodologies for classical demand planning, do not properly depict the real situation. To show how the electric grid characteristic has changed over time, Figure 1 presents two histograms of active power flow measurements between the transmission and the distribution grid (380kV/110kV) for the years 2006 and 2013, respectively. As marked in Figure 1, negative values of the active power flow represent reverse power flow conditions from the distribution to the transmission grid.
The interaction between the DG and the load can be seen in the difference between the two presented years. The expected value of active power flow in the year 2013 is lower than in 2006. Since the general load situation in the considered grid did not change from the year 2006 to 2013 significantly, it can be reasoned that a lot of high load situations in 2013 occurred simultaneously with the power infeed from the DG.
The reverse power flow conditions require new considerations for the planning process of the grids. Particularly in meshed power grids, it is almost impossible to predict a reverse power flow scenario that represents the maximum loading of all lines in the surveyed power grid. So, the bi-directional power flows lead to new requirements for the planning process of distribution grids [1].

PLANNING APPROACH

Several approaches to optimize the planning of electric power grids have been published. One option is the use of reliability indices instead of the (n-1)-security, e.g. the LOLE (loss of load expectation) and EENS (expected energy not served) [2]. Other authors support the cost evaluation of network reinforcements by solving optimization problems [3] or evaluating the maximum capacity of DG that can be connected to the distribution grids [4]. 110kV-grids are planned as meshed grids to ensure (n-1)-security.

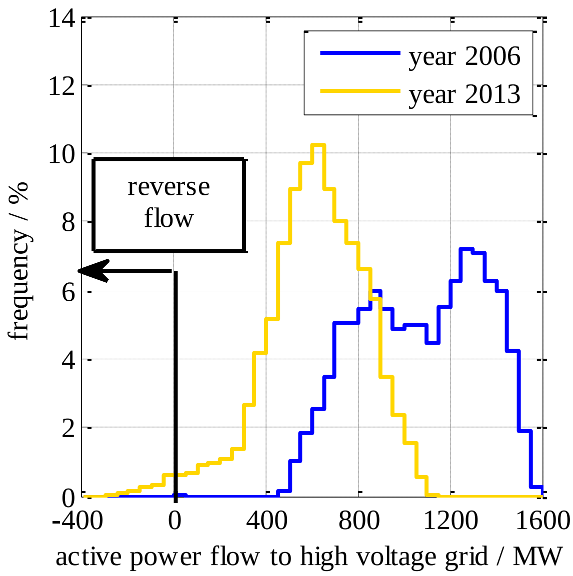

Figure 1: Histogram of active power flow between the distribution and transmission grids (negative values represent power export from the distribution grid)

Present-day approaches use predefined scenarios for the calculation of the grid reinforcement. However, it is not guaranteed that the predefined scenario represents the most critical case in a contingency analysis, especially for the reverse power flow condition [5]. The new hybrid planning approach considers this new situation within the power system. For this the contingency analysis is based on a probabilistic load flow (PLF) calculation. Therefore, several contingency analyses are performed for the extreme scenarios in the PLF. This is different from the present-day approaches that use a small number of predefined deterministic scenarios. Table 1 shows an overview of the differences between the present-day approach and the proposed hybrid planning approach.

The main difference in the new hybrid planning approach is that a combination process merges the probabilistic methodology in the first step with the deterministic methods in the following steps. This allows us to consider a lot of different load-generation situations (theoretically all possible combinations) and to better characterize the resulting loading conditions of each individual line.

Present-Day Planning Approach

In the present-day planning approach, an estimation of required transport capacity is realised with a low number of scenarios. Usually, two worst-case scenarios are used, one for high load with low DG and one for low load with high DG [6]. For the high load scenario, the power values of all loads are chosen in a way that represents the maximum active power flow from the transmission grid. The low load with high DG scenario is calculated to consider a reverse power flow [6]. For this scenario the chosen power values would represent the lowest active power flow, e.g. in Figure 1 for the year 2013 -300 MW. The present-day approaches have the premise that those two scenarios represent the maximum loading of all lines. Based on the meshed structure of the 110kV-grids, however, it is possible that individual lines have higher loadings than represented in the two scenarios. In the contingency analysis, a calculation is executed to see if grid reinforcement is necessary. Therefore, a single element outage (n-1 contingency) is modelled and limits of the operational conditions are checked for each line and each contingency [5]. This is done to detect whether the considered system complies with the (n-1)-criterion [5]. If the system is not (n-1)-secure, the network has to be reinforced and the contingency analysis is repeated [1]. The necessary grid reinforcement is reached, if the system has an (n-1)-security. Normally, a cost evaluation is done for several network reinforcement scenarios and the best configuration is chosen [1].

Hybrid Planning Approach

In the hybrid planning approach, the grid reinforcement is based on PLF calculations. This pursues the target to optimize the grid structure reinforcement for a high penetration of RES, while reducing the unnecessary measures.

Table 1: Overview of the differences between the Present-day and the hybrid planning approaches

	Present-Day	Hybrid
Load Flow Calculation	Deterministic	Probabilistic
Input Data	Usually two worst-case scenarios	Many ("all") load and generation scenarios
Contingency Analysis	Predefined	Based on loading of lines

For the contingency analysis in the hybrid planning approach, the tested load scenarios are chosen based on the results of the PLF. Here, a contingency analysis is performed for every load scenario that represents a maximum loading of each line in the PLF. Therefore, the (n-1)-security will be tested for each line in its individual maximum loading. A flowchart of the whole process is given in Figure 2.

The measured time series for active and reactive power at all substation transformers (110kV/MV-grid) and time series of a climate model is used as input data for the hybrid planning approach. A probabilistic load flow is calculated over the period of one day with a resolution of 15 minutes, which could be even further refined if the input data are available in the required form. However, a higher resolution is generally not necessary, since the short-time overload situations are usually not critical for the power grid components. This results in 96 PLF calculations per day and allows the integration of new control mechanisms in further work (grey color in Figure 2) such as demand-side management, storage systems or active- and reactive power control. Based on the results of the PLF, the scenarios that represent a maximum loading of one line are chosen for the contingency analysis and the necessary network reinforcement is estimated.

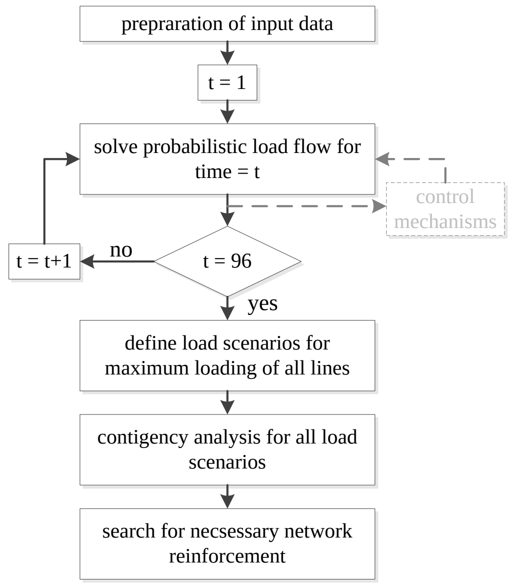

Figure 2: Flowchart of the hybrid planning approach

PROBABILISTIC LOAD FLOW

To solve the PLF calculation a Monte Carlo approach is used in the proposed planning process. To model correlations of stochastic variables, here the active power data, a Monte Carlo simulation is the only approach that can be used for a PLF [1].

Methodologies of Probabilistic Load Flow Calculation

The several methods that can be used to perform PLF calculation can be divided into analytical solutions, approximate methods and Monte Carlo simulation [7]. First, analytical solutions of PLF are proposed, which usually require approximations to solve the non-linear load flow equations [8]. Therefore, these equations are solved with convolution techniques for the probabilistic density functions of the power injections [8], [9]. Another method for an analytical solution is the use of cumulants and the characteristic function of random variables [10]. Approximate methods estimate the solution of the PLF calculation by using several density estimators [7], [11].
Over the area of an 110kV-grid, the power infeed of RES is correlated to the weather conditions. For the considered 110kV-grid, the correlation coefficient for active power infeed for photovoltaic units (PV) is 0.86. For wind turbines, it is 0.66. According to [12], this can be interpreted roughly as positively correlated values of the active power infeed. To consider such correlation, the PLF is solved with a Monte Carlo simulation in the proposed method, which is the only solution able to consider such complex correlations [1].

Preparation of Input Data

As input data for the PLF calculation, active and reactive power time series are needed. The residual load is measured at the substation transformers. To obtain the time series of the demand, the residual load is rectified by the power infeed from RES. To model the power infeed from RES and their correlation to the weather condition, a climate model is used that provides regionally specified time series for wind speed and solar radiation. The correlation coefficient over the considered area in this data based on the climate model is nearly the same as the measured data of the RES, which proves the validity of the climate model. Based on the climate model, the electric power of the RES is estimated with the primary energy and electric power characteristic. Therefore, the dependency of electric power on wind speed for wind turbines and on radiation for PV is used. For the determination of the final time series of the active power (residual load profiles) at the substations, the power infeed of RES is added randomly to the rectified load data.
To compare the model with measurements, Figure 3 shows the mean values of one substation for a summer workday in 2013. Additionally, the standard deviation of active and reactive power at selected time-points is presented in Figure 3 by the error bars. The mean values show a high compliance between the modelled and measured data. Since RES usually has a power factor equal to one [6], the reactive power is modelled with a time-variant load factor.

Comparison between Deterministic and Probabilistic Load Flow Calculation

Since the scenarios for distribution grid planning in the present-day approach are predefined, it is possible that those scenarios do not represent the maximum loading of each line. To evaluate both approaches the line loadings of the predefined scenarios and the PLF are compared with each other. For every season of the year (winter period, transition period, summer period), a Monte Carlo simulation with 1000 iterations is performed, every iteration consists of one day with a resolution of 15 minutes. The bars in Figure 4 show the 20 lines with maximum loading of both scenarios in the present-day approach. Overlaying a boxplot with median, quantile and 1st and 99th percentile shows the PLF result.
The line loading values are all lower than 100%, which results from the "fit-and-forget strategy" [3]. According to which, the grid is planned in the past and any network reconfiguration is done, until the grid reinforcement is required due to a new line overloading. Remarkable in Figure 4 are the differences between the line loading in the present-day approach and the 99th percentile of PLF. The five highest loadings in the present-day approach show lower loadings in the PLF. Contrarily, the lines with a lower loading in the present-day approach often show higher loadings according to the PLF approach. So the predefined scenarios in the present-day approach do not depict the real maximum loading of particular lines.

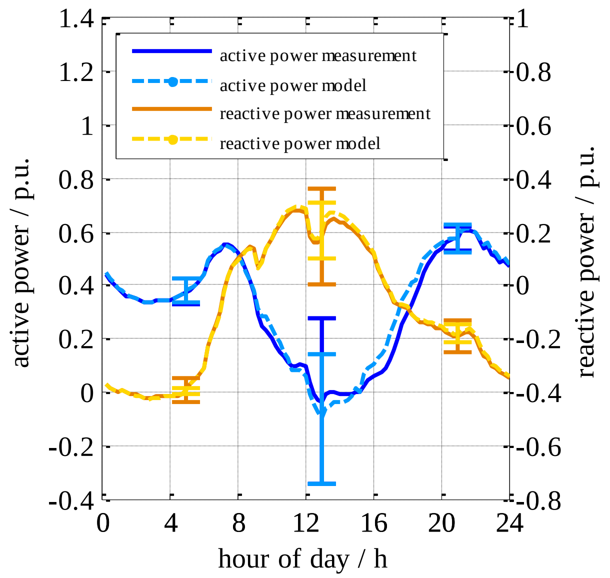

Figure 3: Measurement and model of active and reactive power flow at one substation (negative values represent power flow from the MV-grid to the 110kV grid)

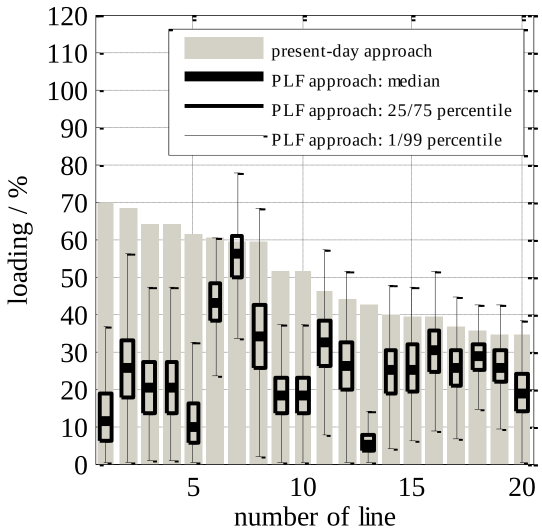

Figure 4: Line loadings in the present-day and hybrid (probabilistic) planning approach

The difference between the predefined deterministic scenarios and the PLF is driven by the ongoing increase of DG. An exemplary time curve of the loading of line No. 3 is plotted in Figure 5. In the grid area near that line, there is a high installed capacity of RES, especially PV. Therefore, the highest line loading is at noon, which is caused by a high power infeed of DG and a reverse power flow situation.

The present-day approach is plotted at a constant value over time in Figure 5. Here, the maximum loading of the two load scenarios is shown. Further, it can be noticed that the minimum, mean and 99th percentile of the loading in the PLF approach are always lower than in the present-day approach. The maximum of the PLF is higher than the present-day approach only at noon.

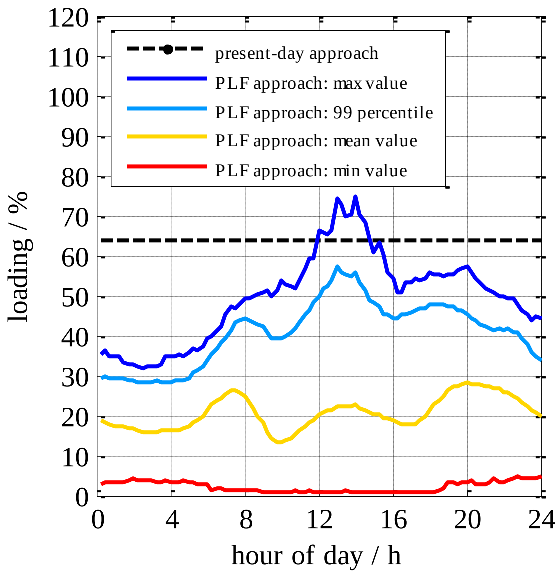

Figure 5: Loading curve of line no. 3 from Figure 4

Compared to Figure 4 the value of maximum loading presented in Figure 5 (equal to 75%) is about 30% higher than the 99th percentile in Figure 4 (equal to 47%). This clarifies that the very high line loadings have a small probability of occurrence, which was also shown in Figure 1 with the small frequencies for reverse power flow scenarios. The maximum load scenario is necessary for the contingency analysis, because the (n-1)-security has to ensure that an outage does not result in any system problems, and an outage is possible in every state of the electric grid [5].

CONTINGENCY ANALYSIS IN THE HYBRID PLANNING APPROACH

As already mentioned, the 110kV-grids are planned with an (n-1)-security. Therefore, in the contingency analysis the power flows are calculated in the outage state, if one or more system components are out of service [5]. This process is repeated to check for an outage in each element. Finally, the system is checked to see if the outage has resulted in any system problems, e.g. overloading of a line [5].

Definition of Scenarios for Contingency Analysis

As opposed to the present-day approach, the contingency analysis is performed for more scenarios in the PLF approach. To test if the considered 110kV-grid fulfills the (n-1)-security in every state, a contingency analysis has to be done for every load scenario. To reduce the computational burden in the proposed hybrid planning approach, the contingency analysis is performed for each load scenario that results in a maximum loading of a particular line. In each contingency analysis the power flows are calculated for an outage of every line separately. Thus, the number of contingency scenarios is equal to the number of lines in the considered grid. This approximation is assumed to be sufficient, since the chosen scenario represent the worst case for each line.

In the hybrid planning approach, it is additionally possible for planners of distribution grids to define an acceptable probability of overload occurrence [1]. This can be compensated by control mechanisms of DG or demand side management. Therefore, the chosen scenarios for contingency analysis may be the 99th percentile instead of the maximum loading [1]. Thus, the planner accepts a probability of occurrence of 1% that the grid does not comply with the (n-1)-criterion without control mechanisms. As shown in the exemplary line in Figure 5, this small probability of occurrence results in a higher transport capacity of 30% for the normal state of the grid. Furthermore, the risk for a supply disturbance is very small. Hence, the outage of an element has to occur 1% of all times to result in a supply disturbance.

(n-1)-Security Based on Probabilistic Load Flow

For both planning approaches, a comparison of the contingency analysis is done with the overloaded lines in the outage states of the system in which one line is out of service. Those lines are shown in Table 2. For the present-day approach only line loading values over 80% are registered during the calculation. Therefore, the lines No. 2 and No. 23 have no discrete values in the table for the present-day approach. In Table 2 the lines No. 3, 4 and No. 9, 10, respectively, are parallel lines which result in identical loadings in both approaches.

Here the contingency analysis shows that the maximum loading in the outage states occurs for an outage of one of the parallel lines. Therefore the loading of each line roughly doubles. So the necessary transport capacity is driven by the outage state. For those lines the difference between the amount of loading in the present day and the hybrid approach is remarkable, here more than 30%. This shows that the predefined scenarios do not represent reality properly, and the tested (n-1)-security does not show the real grid states. The reason for this difference is in the meshed structure of the 110 kV grids. The predefined scenarios in the present-day approach are too different from the maximum load in single meshes in the real grid. Here, the hybrid approach has a benefit compared to present-day approach, since such load scenarios are detected in the PLF and a sufficient transport capacity for a (n-1)-security in every load scenario is calculated.

CONCLUSION

The persistent increase of DG introduces many uncertainties in the grid planning process. In present-day approaches, the grids are usually planned with two predefined worst case scenarios. It is possible that those scenarios do not represent the maximum loading of each line, especially in meshed grids. In this paper a new hybrid planning approach is presented that combines a PLF with a contingency analysis. By using the individual maximum loading of each line based on the results of the PLF, every worst case is then considered in the contingency analysis. This approach was tested on a real 110kV-grid. First, the results of the PLF showed that the predefined scenarios in the present-day approach do not represent the maximum loading of each line in most cases. Additionally, the results showed that very high loadings of each line have very small probabilities of occurrence.

The necessary transport capacity of each line is driven by the contingency analysis. Here, the difference is significant and some lines would be undersized when using present-day approaches, if they are not compensated by the heuristic knowledge of the grid planner.

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Table 2: Overloaded lines in the contingency analysis

	Loading	
	Present-Day	***Hybrid***
Line No. 3, 4	127.1%	135.1%
Line No. 9, 10	102.4%	136.6%
Line No. 2	< 80%	102.3%
Line No. 23	< 80%	101.2%

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