PROBABILISTIC CASCADING EVENT RISK ASSESSMENT

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***Abstract*—This paper describes an algorithm for the identification of rare events with high severities, potentially leading to blackouts in power systems, and the quantification of the risk a given system state holds. Based on the method of probabilistic load flow, probability density functions of the branch loadings under consideration of the forecast uncertainty are determined. From that branch tripping probabilities are derived. Using these tripping probabilities, numerous cascades are simulated. As the main output of this method the overall risk is calculated. This method is applied to the IEEE 118-bus test system extended by uncertainty data and outage statistics.**

Keywords—Cascading events; risk assessment; probabilistic load flow; tripping probability; redispatch

I. INTRODUCTION

The forecasting procedure in operational day-ahead-planning actually used by European TSOs consists of the load prediction based on a reference day, the power plants' generation schedules and the export balance forecast. The rising amount of intra-day trading and the large-scale introduction of renewables introduced a new uncertainty to the forecast procedure, leading to the need of an advanced risk assessment tool taking into account uncertainties. The common practice of TSOs is to perform deterministic n-1 calculations to ensure the grid's security. This method is not capable of taking uncertainties into account and so there is an upcoming need for risk based security analysis.

Due to the above mentioned reasons risk based security assessment was in the latest past a central topic of numerous research publications leading to various different approaches. There are methods based on branching process models to estimate the probability of the outage size of a given grid state using different underlying offspring distributions proposed e.g. in [1], [2] and [3]. Other authors use Monte Carlo simulation to account for the effects of changes in load flow on the outage risk of branches in different degrees of detail e.g. in [4], [5] and [6] leading to the estimated energy not supplied and also the probability distribution of lost load.

The proposed cascading risk assessment method determines each branch's tripping probability based on power system specific data and a given dispatch. It performs a cascade simulation by sequentially tripping potentially threatened branches according to the flow chart given in Fig. 1. Each branch's risk as well as the overall system risk can be calculated and used as a benchmark for comparison of different dispatches and system states. The single branch outage probability is not direct a measure for a cascading event, but a cascading event consists of multiple single, or also multi element outages. The input data of this method is the system topology including electric branch data and their outage statistics, nodal load and generation data with its forecast uncertainty and inter-nodal correlation coefficients, limits for the system frequency, generator droop and self-regulation of load.

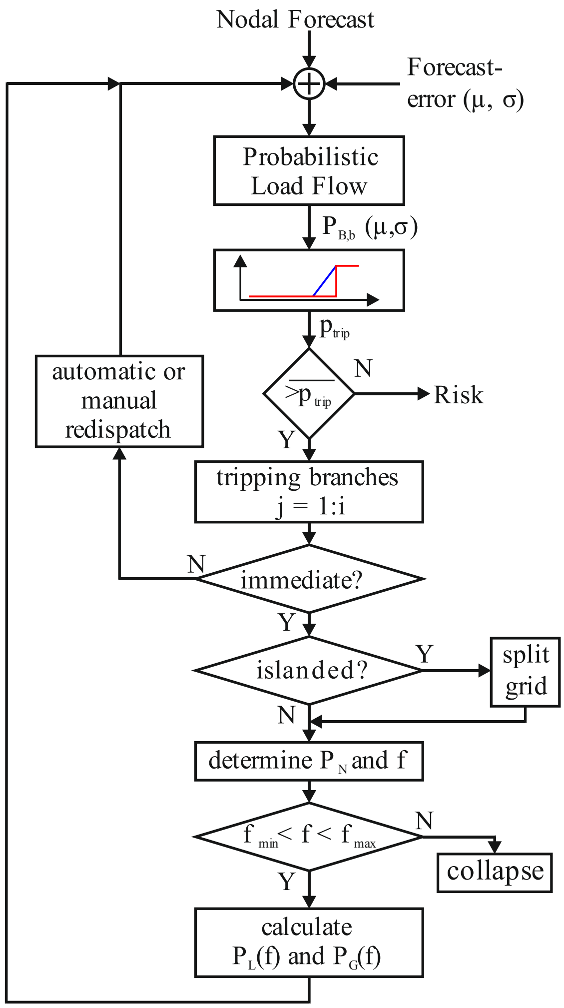

Fig. 1. Method's flow chart.

The approach of the probabilistic load flow is used for the calculation of the branch loadings' probability distributions. This is performed for the sake of computational efficiency by the use of DC-PTDFs (Power Transfer Distribution Factor). The implemented probabilistic load flow takes inter-nodal

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correlations into account. Based on the probabilistic load flow's output and a heuristic function describing the relation of normalised branch loading and branch tripping probability the cumulated tripping probability per branch is computed. This branch tripping function reflects random outages and increasing tripping probability at overload as well as protection device operation.

Using the cumulated tripping probabilities as input, the branch to be outaged during the next cascade stage is selected. For the selection of the initial outage and the second outage special rules are applied. In addition to the cumulated tripping probability the mutual interference of the outages is considered. This is done to limit the number of analysed initial outage combinations to a reasonable number. Also the number of sub-cascades is limited, achieving a trade-off between computational effort and completeness. After tripping of a load or a generation unit, frequency estimation is performed emulating primary control. Additionally under-frequency dependent load shedding is implemented. In the case of the absence of immediate branches to trip an automatic redispatch recovering zonal exchange powers representing secondary control as well as a manual redispatch, as it is done by TSOs are performed. A single cascade simulation is stopped when either there is no branch identified as tripping candidate or the estimated frequency exceeds the predefined system limits, finally leading to a blackout. The method's main output is the lost load per cascade multiplied by the probability of the cascade giving a risk measure. Additionally all intermediate results of the individual cascades are available for analysis.

II. Method Details

A. Probabilistic Load Flow

The probabilistic load flow is able to handle forecast uncertainties in the form of normal distributions having a mean and also a variance value per load and generation. In this work the DC load flow is utilised. Facing the fact that this framework is thought to be used in daily business for also short time horizons the DC load flow is used to ensure a result on time. The DC load flow gives approved results for power systems with a X/R-ratio above 4 and a flat voltage profile [7]. These conditions hold in general for transmission systems. The DC load flow equation system can be extended to a PTDF matrix holding all Power Transfer Distribution Factors [8]. These factors enable a direct calculation of how a change in a certain bus load influences the flow of certain branch.

$$\mathrm{PTDF} = \frac{diag(b) \cdot \widehat{C_{ft}^T}}{\widehat{C_{ft}} \cdot diag(b) \cdot \widehat{C_{ft}^T}} = \frac{diag(b) \cdot \widehat{C_{ft}^T}}{\hat{B}} \tag{1}$$

C_{ft} is the connectivity matrix consisting of one row per bus and one column per branch holding one at the beginning node of a particular line and minus one at the end node. b denotes the branch susceptance vector. Due to the singularity of the bus susceptance matrix B which is inverted during the calculation of the PTDFs it is necessary to introduce a slack node. This is done by setting the slack node related entries of C_{ft} to zero. The matrices where the slack bus was introduced are marked with a hat. To avoid the slack node to serve or absorb all difference in power the given nodal infeed and load powers are balanced. This is done by subtracting the summed-up mean values of the generators $P_{\mu G,g}$ and summed-up values of the loads $P_{\mu L,l}$ leading to the amount of imbalance ΔP. B, G and L denote a set of busses, generators and loads and p, g, and l a certain element out of the particular set.

$$\Delta P = \sum_{g=1}^{G} P_{\mu G,g} - \sum_{l=1}^{L} P_{\mu L,l} \tag{2}$$

This imbalance is deployed on all available generators weighted by their maximum power.

$$\Delta P_{G,i} = \Delta P \cdot \frac{P_{G,i}^{max} \cdot \Phi_i}{\sum_{g=1}^{G} P_{G,g}^{max} \cdot \Phi_g} \; \forall i \in G \tag{3}$$

$P_{G,i}^{max}$ is the maximum power of generator i, Φ_i is equal to one, when generator i is online, or zero if it is offline. This calculated change in generation is subtracted from the mean values of the power infeed and leads to a balanced network in terms of the mean value of power.

Regarding the variance σ^2 it is assumed for the sake of simplicity, that loads as well as generation units are not mutually correlated. The overall variance of the load σ_L^2 and generation σ_G^2 needs to be equal to each other and perfectly negative correlated to avoid the slack node from handling the difference in power. So the overall load variance and also the overall variance in generation is calculated as follows.

$$\sum_{g=1}^{G} \sigma_{G,g}^2 = \sigma_G^2 = \sigma_L^2 = \sum_{l=1}^{L} \sigma_{L,l}^2 \tag{4}$$

To distribute the variance of the generation units they are weighted by the generators maximum power. Additionally the variable Ψ holds information about the generator being able to provide a variance or not.

$$\sigma_{\mathrm{G,i}}^2 = \sigma_{\mathrm{G}}^2 \cdot \frac{P_{G,i}^{max} \cdot \Phi_i \cdot \Psi_i}{\sum_{j=g}^{G} P_{G,g}^{max} \cdot \Phi_g \cdot \Psi_g} \forall i \in G \tag{5}$$

As mentioned before the equations of the DC load flow are linear and so it is possible to interpret them as a sensitivity factor. These sensitivity factors allow weighting the variances with the squared PTDF [9].

$$\sigma_{B,b}^2 = \sum_{n=1}^{N} PTDF_{b,n}^2 \cdot \sigma_{N,n}^2 \;\; \forall b \in B \tag{6}$$

The linear nature of the DC load flow enables the separate calculation of the branch flows' variances caused by the generating units and the loads according to eq.(6). Correlated variances are summed according to eq.(7) [10].

$$\sigma_{B,b}^2 = \sigma_{L,b}^2 + \sigma_{G,b}^2 + 2 \cdot \rho_{LG} \cdot \sigma_{L,b} \cdot \sigma_{G,b} \; \forall b \in B \tag{7}$$

Thus this approach provides a method for calculating load flows for infeed or/and load data being uncertainty afflicted in terms of normal distributions with a mean value μ and a standard deviation σ.

B. *Inter Element Correlation*

The approach presented in the previous section accounts for the negative correlation between generation and load, but not for the intra-load-correlations of loads like highly correlated load collectives or the intra-generation-correlation like in the case of wind parks or numerous photovoltaic units in the same geographical region. However, depending on the degree of integration of such correlated energy sources and sinks the correlation between the certain elements (vertical grid node and direct connected generation units) differs from perfect correlation and is assumed to be given per element in a matrix. The number of elements is here defined as the sum of the number of generators and the number of loads ($E = G \cup L$). So the correlation matrix is a number of E square matrix. Obviously each entry of this matrix' main diagonal is equal to one due to the perfect correlation of each element's power consumption with itself.

The handling of the mean values stays unaltered, except the computation of the branch loadings' variances to implement the ability of taking above mentioned correlations into account. This can be realised by calculating the effect of each grid element onto all branches by the use of the belonging PTDFs.

$$\sigma_{b,e}^2 = PTDF_{b,e}^2 \cdot \sigma_{E,e}^2 \;\; \forall e \in E, b \in B \tag{8}$$

Summing up these variances according to their correlation factor given by the matrix of correlation coefficients ρ leads to the final variance of the line.

$$\sigma_{B,b}^2 = \sum_{i=1}^{E} \prod_{j=1}^{E} \rho_{i,j} \cdot \sigma_{b,i} \cdot \sigma_{b,j} \;\; \forall \; b \in B \tag{9}$$

It's obvious, that the sum of all elements' variances including correlation, but not weighted by the PTDFs needs to be zero, meaning that all load cases are balanced. So this approach is able to deal with uncertainties being normally distributed as well as correlated.

C. *Branch Outage Probabilities*

Triggers for branch outages can be malfunctions of protection devices, natural phenomena like storms, avalanches or direct as well indirect lightning strokes, misoperation leading to increased line sag ending with a line-earth fault of overloaded lines.

Branch tripping is implemented according to the actual loading of the element. A distinction between immediate and delayed outage was done. The terminus immediate outage is used when the system operator has no time to take actions due to un-delayed tripping by protection devices. For a delayed outage, a certain element loading must persist for a certain period before protection relays trip the element. This can be due to delayed overcurrent protection or tripping after increased line sag following a longer period of overload. However, in those cases the TSO might have the possibility to activate remedial measures.

To reflect the basic risk of operating a branch regardless the branch flow – so to say the unavoidable tripping probability – outage statistics of independent single element events where used. These values published for instance in [11] are available for different voltage levels and element types such as transformers, overhead lines and cables. Since those number are quite low even for long lines, it's justified to assume that during a time span of an hour an independent line trip will occur not more often than once. Following that assumption, the outage frequency according to [1] can be interpreted as number of hours experiencing an outage during an observation time of 8760 hours. Thus the probability of facing an hour with a certain element tripping becomes simply the element's yearly fault frequency divided by 8760 hours.

For a branch loading that exceeds overload protection settings, an immediate tripping with probability 100% occurs. In the simulation the protective limit is an arbitrary input parameter for each branch.

Regarding delayed outages and hidden failures of protective relays [6] the range in branch loading between 1.0 p.u and the protective limit is assumed to show a linear increasing outage probability for delayed outages as shown in Fig. 2 with the overload protection limit exemplarily set to 1.5 p.u.

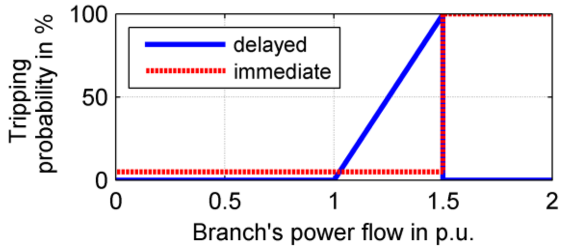

Fig. 2. Probability weighting functions.

In Fig. 3 the approach is demonstrated exemplarily for a branch loading distribution (upper plot), which is weighted according to the weighting function in Fig. 2. The weighted curves for immediate and delayed outage (lower plot) are integrated and thus provide the actual outage probability of a certain branch. The red-dashed line represents the weighted immediate tripping probability whose cumulated value is 19.8% and the solid line represents the delayed outage potential according to the branch loading given in the first subplot whose cumulated value is 44.1%.

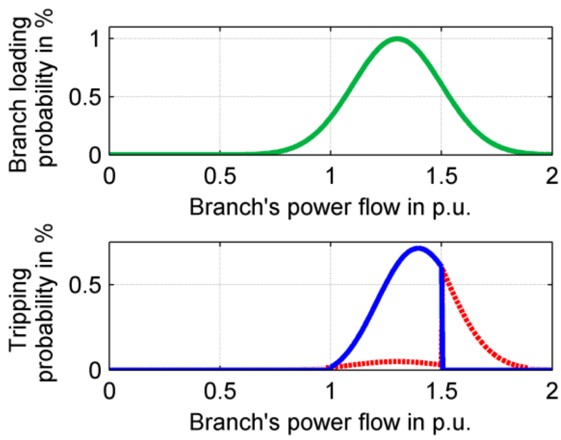

Fig. 3. Branch outage probability calculation.

D. Selection of Outages

The selection of the branch(es) to be outaged is based on several conditions. If immediate outages are identified they always trip first. If there are no more identified immediate outages the delayed ones are processed.

To avoid the exhaustive simulation of all N-2 triggering events in the first stage all immediate outages of branches holding a tripping probability exceeding a given limit are simulated. In the second simulation stage the outage criterion of stage one is extended to identify only branches, showing a change in branch loading due to the outage in stage one and exceeding a given limit of 5%. Above the second stage a branch needs to fulfil the following terms. On the one hand the absolute value in change of the load flow during the last outage stage to the actual one needs to exceed 10% of the branch's rated power and on the other hand also the cumulated branch tripping probability needs to be higher than a given limit. It turned out that the conditional probability is a good criterion for limiting the depth of the simulation, due to the fact that the branch tripping probability increases the weaker a grid becomes. Since in a weak grid branches tend to be overloaded, almost all branches would be candidates if not filtered by the branches' conditional outage probability. It means that the foregone states probabilities are included by multiplying the stage's probability with the outage probability of the branch. If more than one branch exceeds a given limit in immediate tripping probability they are tripped simultaneously. If there is no candidate for immediate tripping, preventive measures by the TSO are possible. Manual redispatch as well as automatic secondary frequency control are enabled. The secondary frequency control leads to a restoration of the grids nominal frequency and compensation of the area control error. After the secondary control a manual redispatch is enabled if there are branches in the grid exceeding a limit of 1 p.u.

E. Primary Frequency Control

Primary frequency control (automatic generation control AGC) is used to balance generation and load. It is integrated by the use of the self-regulation effect of loads and the droops of power plants taking part in this control scheme. The droop σ is given in % and recalculated to MW/Hz according to formula (10) where P_N denotes the nominal power of a generation unit and f the frequency.

$$\frac{\Delta P}{\Delta f} = \frac{P_N}{f \cdot \sigma} \tag{10}$$

The self-regulation effect (λ_l) is assumed according to [12] to be 1%. So the overall grid frequency response on an imbalance in the system can be approximated by eq.(11).

$$\Delta f = \frac{\sum_{g=1}^{G} P_{G,g} - \sum_{l=1}^{L} P_{L,l}}{\sum_{g=1}^{G} \frac{P_{G,g}}{f \cdot \sigma_g} + \sum_{l=1}^{L} P_{L,l} \cdot \lambda_l} = \frac{\Delta P}{\frac{\Delta P_G}{\Delta f} + \frac{\Delta P_L}{\Delta f}} \tag{11}$$

The change in power as a response on the frequency deviation can be determined by simply multiplying the gradients of the generation units, or the loads self-regulation coefficient by the deviation in frequency according to eq.(12) and (13).

$$\Delta P_{L,l} = \lambda_l \cdot \Delta f \;\; \forall\, l \in L \tag{12}$$

$$\Delta P_{G,g} = \frac{P_{G,g}}{f \cdot \sigma_g} \cdot \Delta f \;\; \forall\, g \in G \tag{13}$$

F. Secondary Frequency Control

In real world grid operation the objective of the secondary frequency control is to restore the frequency and release primary frequency control reserves. Facing the fact that the primary frequency control depends on the system frequency, all power plants in the synchronous area participating in the control pool react according to the set droop. After replacing primary frequency control reserves by secondary frequency control units in the affected control zone, the import/export balance of control zones is restored automatically. This procedure is valid while no islanding activity was detected in the grid. In case of islanding the affected grid zones wouldn't be able to restore their exchange powers and so the control scheme is changed from the exchange powers objective to a frequency control. In this method the secondary frequency control is implemented by restoring exchange powers during normal grid operation meaning a non-islanded grid state by the use frequency gradients. When islanding is detected secondary frequency control actions are disabled. To allow a zonal-consideration in terms of power balance the nodes in the grid are assigned to their particular control zone. In (14) the formula for the calculation of all export powers (ΔP_{zone}) of all zones in the system is given.

$$\Delta P_{zone} = \psi_{ZN} \cdot (\psi_{NG} \cdot diag(\Phi_G) \cdot P_G - P_L) \tag{14}$$

ψ_{ZN} is the membership matrix with dimensions of zones in terms of rows and nodes in columns holding one on row i and column j when node j is a member of zone i. Further on ψ_{NG} is the member matrix having number of nodes rows and number of generators columns being in row i and column j when generator j is connected to bus i. P_G denotes the vector of mean values of all generators and Φ_G gives the status of the generator being one when at position j when generator j is online. P_L holds the mean value of all nodes' power consumptions.

By the knowledge of the actual zone balance and the desired zone balance the deviation in balance per grid zone can be calculated causing again a difference in overall power balance leading to a frequency deviation according to eq.(15).

$$\Delta f = \frac{P_{Exchange} - \Delta P_{zone}}{\frac{\Delta P_G}{\Delta f} + \frac{\Delta P_L}{\Delta f}} \tag{15}$$

The change in power infeed and consumption of the load can be determined in exactly the same way as described for the primary frequency control by eq.(12) and (13).

G. Redispatch

The implementation of a delayed tripping not only enables the possibility for the automatic secondary control, but also the TSO to take manual preventive or corrective measures. This are in the most cases predefined action schemes giving measures after certain congestion. Due to the fact that these measures are difficult to model without detailed informations on each remedial action a DC-OPF including a pre-filtering is formulated. Due to the fact, that the computation time of the DC-OPF dramatically increases with the degrees of freedom (here the number of redispatchable generators) a selection of at least two candidates per overloaded branch is proposed to keep the optimization time low. Therefore the PTDF matrix is transformed by applying formula (16) to give the change in branch flow depending on each generator's power infeed.

$$PTDF_{B,G} = PTDF \cdot \widehat{\Psi}_{NG} \tag{16}$$

The linearity of PTDF factors allows the use of equations also in differential form to only handle the amount of overloading. There are several limitations in real life grid operation for power plants to be candidates for a particular redispatch, namely the possible relief of the congested element, the reserve capacity of the participating redispatch generators in terms of an increase or decrease in power and the corresponding gradients. The reserve is taken into account by determining the maximal increase in generation according to eq.(17) and the maximum decrease according to eq.(18) (assuming the unit can be power off).

$$\Delta P_G^{max} = P_G^{max} - P_G \tag{17}$$

$$\Delta P_G^{min} = -P_G \tag{18}$$

The maximal possible redispatch $\mathrm{P}^{\mathrm{red}}$ is limited by the minimum change in power of the particular generators in positive as well as in negative direction. To get this measure the minimum value for each combination of the vectors ΔP_G^{min} and ΔP_G^{max} non-equal index elements is computed. Equal index elements are set to zero.

$$\mathrm{P}_{\mathrm{i,j}}^{red} = min\left(\left|\Delta P_{G,i}^{max}\right|, \left|\Delta P_{G,j}^{min}\right|\right) \begin{array}{c}\forall\, i,j \in G \\ i \neq j\end{array} \tag{19}$$

To enable the evaluation of a certain redispatch's effect on a congested branch for all generator combinations the difference of the generator based PTDF values is calculated for each congestion and multiplied by the redispatch amount according to eq.(20). Due to eq.(19) the power of the generator i is increased during the redispatch and due to the negative sign in formula (20) the power of generator j is decreased.

$$P_{ij,b} = \left(PTDF_{b,i} - PTDF_{b,j}\right) \cdot \mathrm{P}_{\mathrm{i,j}}^{red} \quad \forall\, i,j \in G, b \in B \tag{20}$$

$P_{ij,b}$ gives the change in the congested branch b for a redispatch utilising generator i and j. The above stated recommendations for redispatch generators are mostly rateable except the distance of them from the congested element. To identify near generators graph theory is used to find all shortest paths between the particular generators and a certain congestion [13]. The output of this algorithm is a matrix with number of generators by number of congested branches here denoted by D_{G,B_c} where B_c is the set of congested branches.

$$D_{ij,b} = D_{i,b} + D_{j,b} \forall i,j \in G, b \in B_c \tag{21}$$

To combine generator pairs' distances and their effect on the branch of interest a distance equivalent $\delta_{G,B}$ is calculated weighting the redispatch partners' effect (limited between no effect and full avoidance of the congestion) in congestion removal by the maximum value of the distance matrix given above according eq. (22).

$$\delta_{ij,b} = max\left(D_{G,B}\right) \cdot \left(1 - min\left(max\left(0, P_{ij,b}/\left(P_{B,b} - P_{B,b}^{max}\right)\right), 1\right)\right) \quad \forall i,j \in G, b \in B_c \tag{22}$$

To find the optimal redispatch generator duo per congestion the minimum of the sum of both, the distance values as well as the distance equivalent is computed.

$$\min_{I_b,J_b \in G} D_{ij,b} + \delta_{ij,b} \ \forall\, b \in B_c \tag{23}$$

The redispatch itself is implemented by the use of DC-OPF. The objective of the optimization is to avoid overloaded branches according to eq.(24) by adjusting the power infeed of the identified redispatch generators ($R = I \cup J$). To increase the weight of highly overloaded branches the branch loading in p.u. is taken into the power of 10.

$$\min_{P_G} \sum_{b=1}^{B} 10^{\frac{\left|P_{B,b(P_{G,R})}\right|}{\left|P_{B,b}^{n}\right|}} \tag{24}$$

The optimization region is limited by two hard constraint inequalities regarding the redispatchable power plants' powers shown combined in formula (25) ensuring, that the generation power doesn't exceed its maximum and minimum (here presumed to be zero) ratings.

$$0 \leq P_{G,r} \leq P_{G,r}^{max} \ \forall r \in R \tag{25}$$

Further on the sum of the redispatch amount has to be zero.

$$\sum_{r=1}^{R} P_{G,r} = 0 \tag{26}$$

H. Islanding

Islanding detection is implemented by the use of graph theory to find independent sub-grids and disconnected nodes [14]. A simple criterion to decide whether an island is stable in the sense of frequency stability, the ratio of power imbalance immediately after islanding and rated power of connected generation is calculated. If that number exceeds 0.2 it is assumed that the islanded grid will collapse.

III. Demonstration

A. System Description

For demonstration purposes a modified version of the IEEE 118-bus network [15] is used. Line lengths were estimated and outage statistics from [11] applied to lines and transformers For load uncertainty the variance was chosen to be 50% of the given dispatch's power in load. The intra-nodal and inter-nodal correlation coefficients are set to zero for this set of results. This dispatch was generated by using a standard DC-OPF.

B. Base Case Analysis

The probability density functions of the branch loadings for the initial stage of the simulation for the given power system are visualised in Fig. 4. Only a few branches show probabilities in their tails for branch loadings over 1 p.u.

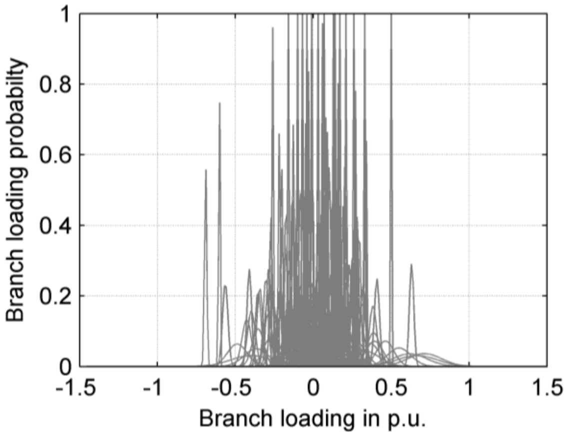

Fig. 4. Branch loading probability density functions.

In Fig. 5 the branch tripping probabilities are shown for delayed and immediate outages in the initial system state. Those tripping probabilities were calculated according to chapter II.C. The delayed tripping probability shows only for branch 129 and 134 non-zero values. This is due the fact that the implemented ramp function for delayed outages gives a high weight to some distribution tails of the mentioned branches.

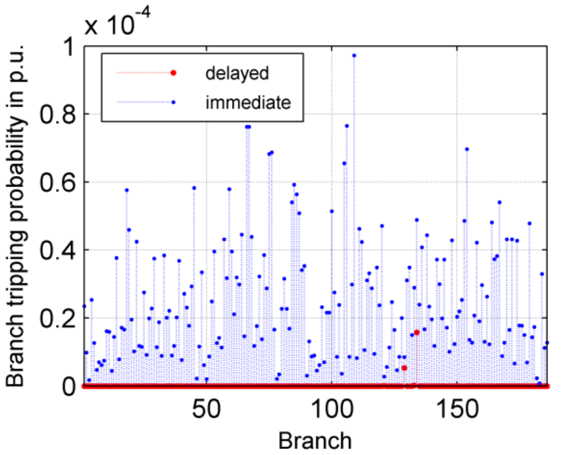

Fig. 5. Tripping probabilities of all branches.

C. *Redispatch*

The developed redispatch method presented in chapter 0 was applied on a congestion that showed up during the simulations. The mean values of branch loadings shown in Fig. 6 demonstrate that in the nominal value is exceeded for eight branches. By applying the proposed redispatch method one of the congestions (branch number 96) could be removed entirely and the other congestions could be eased significantly. This example is a quite stressed grid situation due to various forgone outages as well as redispatches already performed during the past simulation steps.

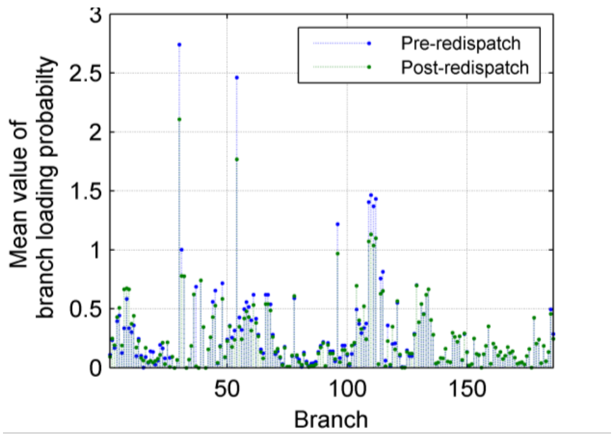

Fig. 6. Branch loadings (mean value) before and after a redispatch.

IV. RESULS

To enable a comparison of results two scenarios were generated. The first one is the standard configuration of the given IEEE 118 bus network and for the second one all branch limits were reduced by 10% to stress the system. Fig. 7 shows the risk each single branch outage holds. It’s obvious that the more stressed system state shows higher values in system risk.

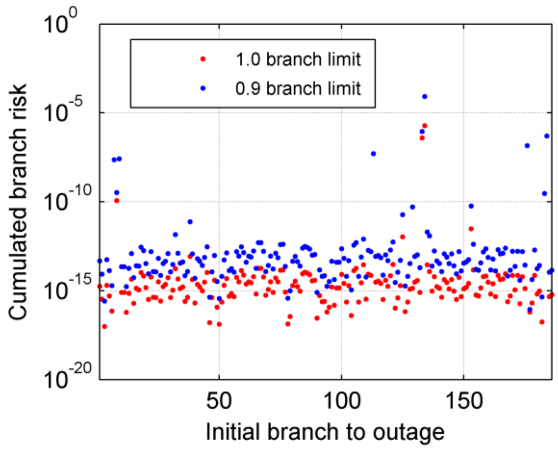

Fig. 7. Risk per initial outage.

The evolution of the cumulative risk is given in Fig. 8.

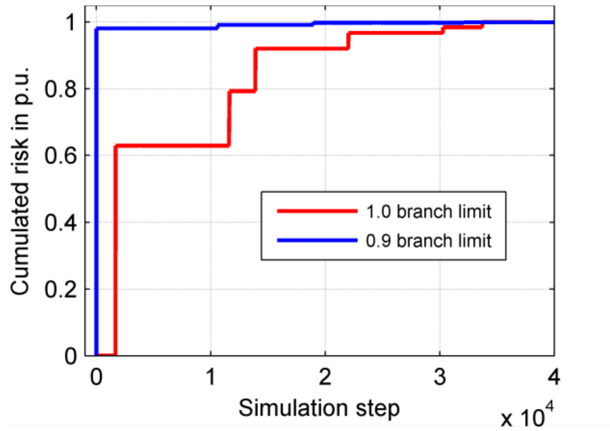

Fig. 8. System risk evolution during simulation.

The red line represents the cumulated risk of the original system state which reaches 95% of its final value after 22033 simulation steps. Compared to this the cumulated risk of the weakened system already exceeds this value after the first simulation step. This leads to the conclusion, that the stressed system contains in this case one outage holding a high risk. Compared to this for the unmodified system numerous simulation steps are required until the risk measure saturates. This is due to the fact, that the overall risk is distributed on various outage combinations and not concentrated in one.

Overall simulation results are shown in TABLE I. The initial stage's probability gives the percentage that the grid remains in the given initial state, the overall probability gives the sum of all simulated states' probabilities and the risk measure is the sum of risks each simulation step holds. The given measures allow a comparison regarding risk leading to the conclusion that the configuration given by the IEEE 118 bus network holds a lower risk than the stressed system.

TABLE I. SELECTED SIMULATION RESULTS

Branch limit	**Initial stage's probability**	**Overall probability**	**Number of simulated cascades**	**Risk in MW**
1	99.53	99.98	38178	3.10E-06
0.9	99.47	99.94	51325	86.1E-06

Compared to the results presented in TABLE I the analysed grid state regarding inter-nodal correlations – presented in TABLE II - shows a significant higher risk, than the comparable grid state regardless correlation. Especially the probability for the power system to stay in the initial condition is quite low for the state including correlations.

TABLE II. SELECTED SIMULATION RESULT WITH CORRELATION

1	76.48	97.48	34878	18.7E-6

V. CONCLUSION AND OUTLOOK

This method allows a risk based security assessment regarding cascading events. Concerning the IEEE 118-bus power system the computation keeps feasible also using quite low limits for branch tripping selection leading to numerous cascade simulations. However the method is not tested on large scale power systems so far. Challenges in calculating real power systems are mainly the data acquisition of the reliability data as well as the increasing computational effort for large scale networks. The presented redispatch method shows a good identification of potential redispatch candidates and leads to a significant decrease in the overall system loading.

The next steps in research will be the investigation of the influence of inter- and intra-nodal correlations, the substitution of N-2 triggering events by a limit for conditional probability. Further on the method will be enhanced to handle also outage combinations not being filtered by a given limit for each single participating outage but the mutual outage probability of all branch sets. Further on the method will be applied to a large scale network as part of the work in the EU research project Umbrella.

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