PETRI NET BASED MONTE CARLO SIMULATION FOR MODELING AND ANALYZING THE RELIABILITY OF DISTRIBUTION SUBSTATION FACILITIES IN BELGIAN POWER SYSTEM

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INTRODUCTION

Optimizing substations assets inspection, maintenance and replacement is considered as a key part to ensure the quality and continuity of service to customers. In order to model and analyze the reliability of distribution substation, utilities are looking for more realistic modeling approaches which permits also to implement a reliability-centered maintenance policy. The paper proposes a stochastic Petri net model used as a support for Monte Carlo simulation; it takes into account the main substation processes and the criticality of different possible failure consequences. Two failure modes are considered for the primary and backup protective systems: on-demand failure and spurious operation. Imperfect preventive maintenance actions are carried out systematically after periodic inspections, and minimum repair is carried out if necessary in the mean time. The simulation results provide support for the decision-maker when comparing different alternatives aiming to improve the substation reliability. As an illustration, we have investigated the effect of the structure of the protective system of the feeder.

1. INTRODUCTION AND PROBLEM STATEMENT

Today’s electric power distribution systems operate in a deregulated market. The system operators are required to provide reliable electricity to customers and in the same time to be cost-effective. This has lead to increased attention to the development of new modeling approaches and decision-aiding tools aiming to improve the substation reliability and asset management.

This paper aims to present part of a research project called COMPRIMA (Cost-Optimization Models for the Planning of the Renewal, Inspection, and Maintenance of Belgian power system facilities). This research work was initiated in order to model and analyze the reliability of a part of, or of the whole power system, as well as the ongoing improvement of its inspection, maintenance and renovation activities; it consists also in implementing a reliability-centered maintenance (RCM) policy.

Substation reliability study is very important because after a fault occurrence on high voltage (HV) facilities: transformer, feeder and bus bar; the primary and the backup protective relays at the substation sends a trip signal to the circuit breakers, which trip in order to isolate the faulted part from the healthy parts of the grid. For a more realistic dependability study of the substation, the following processes need to be considered:

- The fault occurrence process on HV facilities;
- The protective systems (PS) structural dependencies, coordination, failure modes and consequences;
- The switching process in the substation;
- The deterioration process of facilities;
- The maintenance process of facilities;
- The maintenance management and resources.

A simulation approach is needed to take into account most of these constraints [1]. The stochastic Petri nets have proved to be useful tools for modeling both stochastic and deterministic processes present in a system, as well as their interactions. They offer the ability to capture in the same modeling framework different realistic aspects of the problem [2]. To investigate the reliability and maintenance optimization of a simplified feeder, a Petri net based Monte Carlo simulation approach was thus used in our previous works [3], [4]. The same approach is extended in this paper to the whole HV distribution substation shown in Figure 1. This substation presents a double bus (B), single breaker arrangement; it is supplied by two power transformers (T1 and T2), which are connected to the network by two transmission lines (L): AD and AH. Three industrial customers are supplied: two with a single feeder (F), (customers C1 and C3) and one with two feeders (customer C2). The primary PS associated to a feeder or a transformer is called the Main Protective System (MPS) and the primary PS associated to the bus bar is called the Bus Protective System (BPS).

![Substation Diagram](image)

Figure 1. HV distribution substation.

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Should the breaker fail to open ("stuck close breaker"), the backup PSs can be used for fault clearing. Two types of backups are usually employed: a local backup system (LBS) and a remote backup system (RBS) [5]. In the proposed model, we have considered a protection strategy that incorporates all three PSs: MPS, LBS, and RBS, see Figure 2.

The MPS is a multi-component subsystem composed of detection/control subsystems (DCS) in series with the breaker mechanism (BM). Depending on its level of redundancy, each DCS can have two types of structure:
- A simple structure, noted 1B; it is composed of single detection/control branch (see Figure 3);
- A reinforced structure, noted 2B; it is composed of two detection/control branches in active redundancy (see Figure 4).

Each DCS branch is composed of the following components in series: battery system (BA), voltage transformer (VT), current transformer (CT), relay (R), and trip coil of the breaker (TC).

From Figures 3, 4 and 5, we can see that VT and BA are common components for local protective systems (LPS) in the substation. If the DCS structure of the feeders is simple (1B), one of alternatives aiming to improve the substation reliability, and particularly the service-to-customers, is the reinforcement of the structure of the DCS, i.e. the addition of a redundant detection/control branch.
In this paper we use the whole substation model to compare the reliability of the substation in the two scenarios; this comparison is based on the following key performances indicators (KPI):

- The total operational cost;
- The mean availabilities of the feeders;
- The probability of occurrence of some risk-related events: customer loss, bus bar loss and substation loss.

2. MODEL DESCRIPTION

A Petri net model is developed for the substation, taking into account all the constraints described in the problem statement; this large model is divided into smaller ones which represent sub-processes, for example:

- Component states;
- Structural dependencies states;
- Substation switching states;
- Subsystems states for the MPS, LBS, BPS and RBS;
- Maintenance resources states;
- Maintenance management states.

Figure 6 shows a partial Petri net model describing the states related to F1 with reinforced DCS. For each option for the DCS, we have a Petri net model of the substation.

2.1. Deterioration process and failure modes

As the deterioration process can entail one or several failure modes, equipments present in the substation are split in two classes:

1. Equipments with operational failure (OF) mode: the failure occurs when the component operates causing its forced outage (FO); the equipments affected by this failure mode are: T, L, B, CT, TC, VT and BA;

2. Equipments with two failure modes: these failure modes are noted FS and FD, and they characterize the PSs [4]; the equipments affected by these two failure modes are: BM and R.

The FD mode is an on-demand failure, such as e.g. the breaker failing to trip when there is a fault in the protection area, which is called also a “stuck close breaker” failure; it can induce a high damage causing very costly risk events. Before the FD mode occurs at the occurrence of a fault, the PS must be affected by a hidden failure noted FD ON in which it becomes unable to operate on demand [1], [2]. The FS mode is a failure due to a spurious operation, which causes the FO of the equipment and possibly of upper levels of the system: feeder, bus bar, substation…etc. An example of a FS mode is an untimely breaker trip without fault in the protection area.

At this stage of the study, we have assumed that the RBS at buses D and H are not affected by either the FS or FD mode.

2.2. Maintenance process

Inspections are carried out to assess the degradation conditions of the components and to look for hidden failures
of type FD_ON. After the inspection, a preventive maintenance (PM) action is systematically scheduled, and it is carried out after possible minimum repairs restoring the components affected by hidden failures. Two types of terminal connections are defined: that composed of the line and its MPS, noted FDR; and that made of the transformer and its MPS, noted TR. The inspection order is the following: TR1, FDR1, FDR2, TR2, FDR3, and FDR4. When one subsystem is inspected, the inspection of the next one is scheduled after 6 months. The common substation components (LBR, BA and BM7) are inspected and preventively maintained every four cycles. Corrective maintenance (CM) actions on an as-bad-as-old basis are carried out if necessary in the meantime. The component virtual age (τ) is assumed to be a degradation criterion; consequently, the imperfect preventive maintenance (IPM) action rejuvenates the component by reducing its virtual age according to:

\[ \tau_{\text{new}} = \tau - \varepsilon \tau_{\text{old}} \]  

(1)

where \( \varepsilon \) is a factor describing the imperfection level of the PM action; consequently: 0 ≤ \( \varepsilon \) ≤ 1. (\( \varepsilon = 0 \)) means that the PM action is perfect, i.e., the component is in as-good-as-new conditions; however (\( \varepsilon = 1 \)) means that the PM action has no effect, i.e. the component is in as-bad-as-old conditions. It is assumed that \( \varepsilon \) is a random variable, depending on the number of PM actions previously carried out on the component:

\[ \varepsilon(n) = \varepsilon(n-1) + \zeta(n)[1 - \varepsilon(n-1)] \]  

(2)

where \( \zeta(n) \) is a random variable uniformly distributed in the interval [0, 1-exp(-n/NM)]; and NM represents a number of PM actions, after which the component cannot be rejuvenated sufficiently. A very simple modeling of the maintenance resource allocation problem is considered, taking into account a repairmen crew available 16 hours a day.

2.3. Cost model

The total cost on a study horizon is the addition of the following main partial costs:

- Cost entailed by the maintenance process C(M), which includes the costs entailed by: monitoring (inspections), PM actions, CM actions, and maintenance management procedures.
- Cost associated to risk events C(R), which covers the costs due to the following risk events: FD mode occurrence on the MPSs, total service-to-customer loss, and total substation loss.
- Cost entailed by forced outages of feeders C(FO), which represents the costs entailed by unscheduled outages of the feeders.

3. NUMERICAL RESULTS

Using the MOCA-RP software [6], Monte Carlo simulations have been performed on 10000 histories on a time horizon of 214767 hours, i.e. 24.5 years. To take into account the individual history of each component, the initial parameters \( \varepsilon_0 \) and \( \tau_0 \) are calculated before starting the simulation; the initial age of all the components of the substation is assumed to be the same \( \tau_0 = 20 \) years. The transition time distributions are described below:

- Exponential laws for the failure time of the feeders, bus bars and transformers with the fault rate (FR) as parameter;
- Weibull laws for the occurrence times of both the FD_ON and FS failure modes with three parameters: Mean time between failure (MTBF), shape factor \( (b=2) \) is adopted for all components), and location parameter \( (\gamma_0 = \tau_0) \).
- Log-Normal laws for PM and CM action durations with two parameters: Mean time to repair (MTTR) and a 5% error factor \( q=1.77734 \).

A set of numerical results is presented in order to illustrate our investigation based on postulated data. Figure 6 shows the influence of the DCS structure on the total and the partial costs in an arbitrary cost unit (CU); we can clearly show:

- A weak increase in the maintenance cost C(M) entailed by the added DCS branch in each MPS;
- A weak increase in risk-related cost C(R) describing the increase in the number of FD mode occurrences, which is more probable when the structure of the DCS is 1B;
- An important reduction in the costs entailed by forced outages C(FO), which is the most important benefit of the DCS reinforcement.

Each feeder can be unavailable for one or more of the following reasons: scheduled outages, switching process, and forced outages. Figure 7 shows that the DCS structure has no significant effect on the mean availability of the feeder; that can be explained by the fact that the MTBF was assumed to be the same for both the FD_ON and FS failure modes. We can also see that the respective mean availabilities of FDR, \( i=1...4 \), are very close because they have the same configuration; the same remark can be made for TR1 and TR2 whose mean availability is lower than those of FDR, \( i=1...4 \), because the transformer scheduled outage duration is assumed to be higher than that of a feeder.

![Figure 6. Costs variations vs. DCS structure.](image)
These reliability indices can be used in asset management as decision-aiding criterions. Illustrative data were used to display estimations of the reliability of the substation, when the main protective system of the feeders is reinforced by adding a second detection/control branch in active redundancy. Future perspectives include a.o. the improvement of our approach by statistical data analysis, needed for parameters estimation, and the investigation of practical aspects of the degradation process of components, as well as its correlation with the maintenance process.

REFERENCES


