Simulation Models and Implementation of a Simulator for the Performability Analysis of Electric Power Systems Considering Interdependencies

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Abstract

Electric Power Systems (EPS) become more and more critical for our society, since they provide vital services for the human activities. At the same time, obtaining dependable behaviour of EPS is an highly challenging task, both in terms of defining effective business management and in terms of analysis of dependability and performability attributes. A major concern when dealing with EPS is the understanding and the evaluation of the interdependencies between Electric Infrastructures (EI) and the Computer-based Control System (CCS), which controls the status and the activities of EI. Studies on these interdependencies are only at an early stage of development. Major difficulties are the complexity of the infrastructures under analysis and the lack of well-established models and tools for dealing with them. This paper presents an ad-hoc simulator for the evaluation of dependability and performability measures in EPS. The system model the simulator is based on focuses on interdependencies between EI and CCS. Most existing modeling approaches in EPS does not provide explicit modeling of interdependencies among the composing subsystems, so that the cascading or escalating phenomena cannot be deeply analyzed. Our stochastic model is composed by separated and simple, but representative, submodels representing the dynamics of EI and different policies of reactions to disruptions and reconfigurations triggered by CCS. In this way, the simulator aims at providing explicit modeling of the interdependencies between the main subsystems, so the impact on the dependability and performability of the cascading or escalating failures can be analyzed. In this paper, we describe the simulator and highlight the design choices.

Index Terms

Electric Infrastructure, Interdependencies, Computer-Based Control System, Simulation, Stochastic Model, Performability Analysis

1 Introduction

While Electric Power Systems (EPS) become more and more critical for our society, evaluating the dependability and performability measures of such systems is a highly challenging task. Existing EPS are composed by two complex and tightly cooperating infrastructures: the Electric Infrastructure (EI) for the electricity generation and transportation to final users, and its Computer-based Control System (CCS), introduced in addition to existing SCADA systems and devoted to control the dynamics of EI and to trigger the reconfigurations in emergency situations. Significant difficulties to analyze EPS are posed by the very high complexity of these infrastructures and by the tight coupling between them. Moreover, the complex interactions between such infrastructures make harder or just practically impossible both to analyze the overall system and to decompose it to focus on each infrastructure. There is also a lack of well-established theories, models and tools supporting them, since studies on these topics are at an early stage of development. The European Union project CRUTIAL [1], started on January 2006, aims to improve the studies in this field, with explicit focus on interdependencies between EI and the rest of the surrounding environment, in particular CCS. In the last years, given the increasing request for dependable behaviour of EPS, a number of modeling and evaluation approaches have been proposed mainly to analyze the dependability of EPS and the cascading failure risk. A review of some past studies, largely used at present for dealing with EPS, is presented in Section 2.

Our ad-hoc simulator EPSyS tries to overcome some limitations of previous approaches in modeling the interdependencies in EPS. We deal with interdependencies, which we attempt to account for by explicitly considering automatic control methods and adopting a more faithful representation of the evolutions of the main events along time. The developed stochastic model EPSyS is based on is composed by separated and simple, but representative, submodels representing the dynamics of EI and the different automatic and expert-based policies of reactions to disruptions and reconfigurations triggered by CCS. In particular, the model represents:

- the quasi-static dynamics of the electric transmission network,
- the random times to the disruptions of the components (generators, power lines and substations),
- the cascade tripping of the components due to overloads (including the removing of components from service triggered by the protection subsystem and, when the protection subsystem fails, the line failure due to excessive heating),
- the random malfunctions of the protection subsystem due to hidden failures (when the component is incorrectly removed),

- the (automatic and expert-based) generator dispatch, load shedding and reconfiguration operations to react to disruptions.

Moreover, we introduce measures of performability, in order to characterize the behaviour of the whole modeled infrastructure.

The rest of paper is organized as follows. Section 2 presents the major approaches on simulation of electric power systems present in the literature. Section 3 is devoted to the description of the EPs subsystems EI and CCS, including their failure models. The measures of interest are dealt with in the next Section 5. An overview of the architecture of the simulator is presented in Section 6, while the steps composing the simulation procedure are described in Section 7. Finally, short conclusions are drawn in Section 8.

2 Related work

The importance of the addressed critical infrastructure, and the high number of experienced blackouts, have triggered important studies on the dynamics of EPS. An analytically tractable model (CASCADE) of loading-dependent cascading failure is proposed in [2], [3] to evaluate the number of failed components. It neglects the times between events, the structure of the power grid, and the diversity of power system components and interactions. When a component fails, i.e. when its load exceeds a threshold, a fixed amount of load is transferred to other components and cascading failures of further components becomes likely. Under interesting settings of the model parameters, the CASCADE model is well approximated by a branching process [4]. Possible extensions of CASCADE for complex interacting infrastructure systems are also considered in [5], [6]. Of course, an analytical model is necessarily kept simple in order to be manageable, and therefore hardly adequate to represent with realism all the aspects involved in cascading failures leading to blackouts.

Several models based on simulation have been proposed [7], [8], [9], [10], [11], [12], [13], [14], [15], [16] to represent EPS in more detail compared to analytical approaches. A brief summary of some of the available cascading failure simulations and of their modeling details can be found in [17]. The OPA simulation model proposed in [7], [8], [9], [10] represents generators, loads, the transmission network, and the operating limits on these components. In this model, blackout cascades are essentially instantaneous events due to dynamic redistribution of power flow and are triggered by probabilistic failures of overloaded lines. The size of blackouts is determined by solving a standard linear programming optimization of the generation dispatch, consistent with the power flow equations and operational constraints, and the redistribution of power flows is calculated using a linear load flow approximation. The model proposed in [11] uses a DC load flow approximation and a linear programming technique to represent cascading blackouts. It also considers sympathetic trippings of grid elements due to latent failures in protection devices (hidden failures), on a probabilistic basis. Importance sampling is adopted to speed up the simulation. The simulation model proposed in [12] to calculate the expected cost of outages takes into account time-dependent phenomena such as a cascade tripping of elements due to overloads, malfunction of the protection system, potential power system instabilities and weather conditions. A simulation procedure is proposed in [13] to search for dangerous event developments (represented by an event tree) based on the concept of vulnerability region and on voltage stability. This procedure links different static and dynamic models used to asses transient stability, frequency response, voltage stability and steady state system conditions. The simulation stochastic model introduced in [16], and inspired to [7], attempts to provide a comprehensive representation of the complex behavior of both the grid dynamics under random perturbations and the operators response to disruptions. This model considers random repair times for the failed components of EI, random removing of components from service, overloaded-line failure due to excessive heating, generator redispatch and load shedding as possible control system reactions to disturbances, and instantaneous operators response to disruptions.

Most of the existing approaches based on simulation emphasizes the importance of building representative stochastic models for the global system analysis of network reliability and of cascading failure risk. These studies focus on reproducing network disruptions, which eventually lead to blackouts, in order to estimate the vulnerabilities of the system or the impact on the EPS reliability of important network parameters, such as overload or load demand, in presence of disruptions. In most of these approaches, the modeling of the existing SCADA systems and of CCS is not considered explicitly or is very simple. Often, only expert-based methods for the systematic control of large power systems in response to disruptions are (implicitly) modeled, since automated methods are effectively nonexistent [18]. Also, most of existing models proposed to reproduce the behaviour of EPS does not provide explicit modeling of the main interdependent subsystems and of the interdependencies between the main subsystems, so evaluation of the impact on dependability and performability of cascading or escalating failures is not trivial. Only very recently interactions between EI disturbances and the often imperfect human operator control actions have been considered [18]. Moreover, although some approaches consider the evolution of the sequences of disruptions in time, the operator's response to disruptions is typically considered instantaneous. Our simulator attempts to extend current methods, by relaxing some limitations to the representativeness of involved phenomena, such as considering a reaction time for the operator's reconfiguration following a disruption.

3 Overview of the electric power system

The electric power system (EPS) considered in this paper is composed by two complex and tightly cooperating infrastructures: the Electric Infrastructure (EI) and the Computer-based Control System (CCS). The EI is the electric infrastructure necessary to produce and transport the electric power from the generation plants towards the final users (loads). The Computer-based Control System (CCS) implements the control system, controls the dynamics of EI and triggers the reconfigurations of EI in emergency situations.

The EI is composed by the transmission and distribution grids. Each grid can be considered as an extended graph, where each node represents a substation, a generation plant, a load or a combination of generation plant and load, while the arcs represent the transmission or distribution lines. Transmission and distribution grids mainly differ for the values of voltage of their components, for the size of the generators and loads and for their topology (meshed graph versus radial topology).

The main components of CCS are the protection system, the frequency regulation system, the voltage regulation system and the teleoperation (or telecontrol) system of the transmission and distribution grids. The protection system is composed by a set of independent (or loosely connected) local protections. The frequency and voltage regulation systems try to keep constant the frequency and the voltage levels inside the grid. The teleoperation systems control and monitor equipments in remote locations. Each system may be structured in hierarchical levels that differ for their criticality, timeliness and for the locality of their decisions. Local control decisions directly impact on single components. They are only based on the local view of the electric state of a specific component and of the topology. On the other hand, global decisions directly impact on a set of electric components and are based on a global view of the electric state of all components and of the topology. Usually, local decisions are more critical than decisions based on the complete view of the state of the grid. Moreover, the reaction time to the occurrence of a disruption depends on whether the decision is local or global, varying from a few seconds (local) to minutes (global). Finally, when a disruption occurs in the transmission grid, CCS tries to trigger a generation redispatch, load shedding or grid reconfiguration based on the current status of the transmission grid and on an estimation of the optimal response to that disruption.

For the sake of brevity, our discussion will be limited to the transmission grid and to the related CCS.

The simulator is based on a stochastic model of the transmission grid, composed by separated and simple, but representative, submodels which represent the dynamics of transmission grid and the different automatic and expert-based policies of reactions to disruptions and reconfigurations triggered by CCS. These different submodels and their assumptions are described in the next Sections.

4 Transmission grid and CCS model

4.1 Power flow model

The transmission network is composed by m transmission lines ($\mathcal{F}$) and n nodes, with $n = n_G + n_L + n_S$ where n_G, n_L and n_S are the number of generators ($\mathcal{G}$), loads ($\mathcal{L}$) and substations ($\mathcal{S}$), respectively. The topology of the network is described by the $m \times n$ *adjacency matrix* $\boldsymbol{A} = [a_{li}]$, where:

$$a_{ij} = \begin{cases} 1 & \text{if line } l \text{ exits node } i, \\ -1 & \text{if line } l \text{ enters node } i, \\ 0 & \text{otherwise.} \end{cases}$$

In the transmission networks, most lines operate with three-phase alternating current (AC). The real input power at each node i is P_i, which is positive for the generators, negative for the loads and zero for the substations. The maximum power that a generator i can supply is P_i^{max} and the maximum power flow that a transmission line l can carry is F_l^{max}. A line is overloaded if the power flow exceeds F_l^{max}. The impedance of each line l is z_l. The electric state of the transmission grid can be represented by the values of various electric parameters associated to each component of the grids: the voltage, the frequency, the angle, the active and reactive power flow. For obtaining information about the values of all these parameters when the state changes during the evolution of the power grid system, extremely time-consuming or computationally intensive numerical problems should be solved. For example, full nonlinear equations and optimizations are needed even when only steady-state operative conditions are considered [16]. Moreover, the random and cascading disruptions (or disturbances or contingencies) that may occur during the stochastic evolution of the system and the number of simulation batches needed to obtain statistically significant measures of interest require numerous solutions of such numerical problems. Solving repeatedly numerous time-consuming problems is computationally prohibitive. For these reasons, simplifying assumptions are considered with the aim to study the power flow through the network. Following the same standard approach used in [7], [15], [16], the state and the evolution of the transmission grid are described by the distribution of the active power flows which are computed using a linear "DC" (direct current) load flow approximation of the AC system. The model of the "DC" power flow is based on the following simplifying assumptions:

1) The electric transmission grid operates in steady-state conditions. Steady-state refers to power supply reaching a state wherein the voltage and the power flows are nearly constant along time (after at least 30 seconds of operation at a given load), i.e. have reached an equilibrium condition.
2) All voltage magnitudes[1] are 1.0 per unit[2].
3) $\cos(\theta_i - \theta_j) \approx 1$ and $\sin(\theta_i - \theta_j) \approx \theta_i - \theta_j$, where θ_h is the voltage phases at node h.
4) Transmission line resistance is negligible.
5) One of the generators is defined as the *reference node* (slack node), which has voltage angle zero.
6) The total generated power is forced to exactly balance the total load demand, i.e.:

$$\sum_{i \in \mathcal{G} \cup \mathcal{L}} P_i = 0. \tag{1}$$

Under these assumptions, the equations for the "DC" power flow approximation can be derived from the standard AC circuit equations. They can be written as:

$$\mathbf{P} = \boldsymbol{B} \cdot \boldsymbol{\Theta} \tag{2}$$

$$\mathbf{F} = \boldsymbol{b} \cdot \boldsymbol{A} \cdot \boldsymbol{\Theta} \tag{3}$$

where:

- $\boldsymbol{B} = \boldsymbol{A^T} \cdot \boldsymbol{b} \cdot \boldsymbol{A}$ is the $n \times n$ *susceptance matrix*, and $\boldsymbol{A^T}$ is the transpose of $\boldsymbol{A}$,
- $\boldsymbol{b} = diag(b_1, b_2, \ldots, b_m)$ is the $m \times m$ diagonal matrix with each entry $b_l = 1/z_l$ being the susceptance of each transmission line l,
- $\boldsymbol{\Theta} = (\theta_1, \theta_2, \ldots, \theta_n)^T$, is the *node voltage angle vector*,
- $\mathbf{P} = (P_1, P_2, \ldots, P_n)^T$ is the *real power injection vector*,
- $\mathbf{F} = (F_1, F_2, \ldots, F_m)^T$ is the *line power flow vector*.

Equations (2) and (3) give a linear relationship between the power flow $\mathbf{F}$ on the lines and the input power $\mathbf{P}$ at the nodes. The active power flow on the transmission lines are obtained in terms of the voltage phases from equation (3). The voltage phases are obtained from equation (2) in terms of the input power at the nodes, using the zero angle of the reference node and allowing for the singularity of the matrix $\boldsymbol{B}$, which has rank $n-1$ because of the constraint (1). The real power injected at the reference node is computed from equation (1).

4.2 Failure model of the transmission grid

A disruption is the unexpected failure or outage of a generator, power line or substation. Components affected by a disruption are out of service (disconnected from the grid). When a substation is out of service, all the lines connected to the substation are out of service. A *random disruption* may trigger *cascading disruptions* in the grid and *cascading failures* in the CCS. The propagation of a disruption can be stopped by the protections by isolating from the grid the component affected by the disruption. Causes of a random disruption can be events such as: lightnings, tree falls, wear and tear, etc. Causes of a cascading disruption can be events such as: excessive heating of a component due to overloads, failures in the CCS components (e.g., incorrect line trips due to hidden failures in the protections), etc. The components which are out of service can be put back in service only when the cause of the disruption is removed, for example, after the repair or replacement of the *damaged* component (restoration) or after the overload of the component is removed by CCS. Anyway, after a disruption of a component, a time (from a few seconds to hours) must pass before the component can be put back in service. The failure model is based on the following simplifying assumptions:

1) Disruptions for which the component can be put back in service in a few seconds are not considered.
2) When a random disruption occurs, the affected component is considered damaged. In this case, the repair is required to put back in service the component.
3) Random disruptions are statistically independent in space and time.
4) The time of occurrence of random disruptions of a generator, power line or substation (which are in service) can be deterministic or random with general distribution selected among the most common and realistic ones (such as exponential with rate λ_i).
5) The rate of occurrence λ_l of a random line disruption l is proportional to the length of the line.

1. In AC systems, the voltages are phasors specified by a magnitude and an angle (phase).
2. The numerical "per unit" value of any quantity is its ratio to the chosen base quantity of the same dimensions. Thus a per unit quantity is a "normalized" quantity with respect to a chosen base value.

6) The (random or cascading) disruption of a component propagates to a neighbor component j (causing a cascading disruption) with probability $p^{HF}(P_j)$ dependent on the power flow P_j through j and on the subsequent exposures to disruptions. The probability $p^{HF}(P_j)$ represents the failure of the protection, as it will be shown in Section 4.4. In this case the component j is considered damaged, i.e., repair is required to put back in service the component.
7) When the excessive heating of a line l due to overloads causes a (cascading) disruption of l, the line l is damaged (due to a failure of the protection) with probability $p^{HF}(F_l)$, as it will be shown below. Alternatively, with probability $1 - p^{HF}(P_l)$ the line is only disconnected by the protection.
8) For modeling the heating of a line, the spatial variation in the temperature along the line and the lose of heat of each element of the surface of the rod by radiation to the surrounding medium are not taken into account.
9) Transient instability, i.e., the disconnection of one or more generators because of loss of synchronism, has not been (explicitly) considered.
10) A big variation of power flow through a generator in a small interval of time (for example, due to a variation of the load) causes a (cascading) disruption. In this case, the generator i is damaged (due to a failure of the protection) with probability $p^{HF}(P_i)$, otherwise it is only disconnected by the protection, as will be shown below.

From assumption (5), the parameters of the distributions of the time of occurrence of a random disruption of a line l are defined in such a way that $\lambda_l = \lambda L_l$ where λ is the constant failure rate for unit length and L_l is the length of the line. Overloads are caused by reactions to disruptions and reconfigurations triggered by CCS. For modeling the heating of a line l due to overloads, the same approach proposed in [16] is considered, based on the assumption (8). The line temperature $T_l(t)$ at time t is given by the simple approximated equation:

$$T_l(t) = e^{-vt}(T_l(0) - T_{el}(F_l)) + T_{el}(F_l), \tag{4}$$

where $T(0)$ is the initial temperature of the line and

$$T_{el}(F_l) = \frac{\alpha}{\nu}\frac{F_l^2}{V_l^2} + T_0.$$

is the equilibrium temperature of l for $t \to \infty$, where T_0 is the temperature of the medium. The parameters α and ν are defined as $\alpha = 0.239/(\rho c \omega^2 \sigma)$ and $\nu = Hp/(\rho c \omega)$, supposing that the transmission line has constant area of cross-section ω, perimeter p, electrical conductivity σ, density ρ, specific heat c and surface conductance H, with $H = 8 \times 10^{-5}(u/d)^{1/2}$, for a turbolent flow of air with velocity u perpendicular to a circular cylinder of diameter d. When $F_l = F_l^{max}$ the temperature $T_l(t)$ converges to the critical temperature T_{dl}, for which the line l sags and trips. A (cascading) disruption of l due to the power flow F_l, with $F_l \geq F_l^{max}$, occurs when the temperature reaches T_{dl} at some time t_{dl} (measured from the moment when the power flow through l has changed). The time to disruption t_{dl} of line l is derived from equation (4) and is given by:

$$t_{dl}(F_l) = -\frac{1}{\nu} ln \frac{T_{dl} - T_{el}(F_l)}{T_0 - T_{el}(F_l)}.$$

More details are in [16].

The generators cannot fail due to an overload, because produced power cannot exceed a given threshold. For the assumption (10), a generator can fail due to a power flow variation greater than a given threshold ΔP_i^{max} in a given Δt_i^{max} time interval. Thus, a (cascading) disruption of a generator i occurs when:

$$\left| \frac{P_i(t_2) - P_i(t_1)}{t_2 - t_1} \right| > \left| \frac{\Delta P_i^{max}}{\Delta t_i^{max}} \right|,$$

where $P_i(t_2)$ is the new power flow injected on i at time t_2 and $P_i(t_1)$ is the previous one injected on i at time t_1, with $t_1 \leq t_2$.

Restoration of a damaged component is considered in the system model, but it is not yet implemented in the simulator. Considering the transient instability requires a significantly more detailed model. For simplifying the model, in this version of the simulator, the probability of loss of synchronism has been considered equal to zero.

4.3 CCS model

For simplifying the CCS model, the effect on the transmission grid of generation redispatch, load shedding or grid reconfiguration is only considered, and the details of the different components of CCS are not taken into account. The behavior of CCS is structured in two levels (although considering more than two levels is immediate): local (or fast) and global (slower) decision. Each level is characterized by an activation condition, a reaction delay and a (dispatch, shedding and) reconfiguration strategy ($\mathcal{RS}$). The activation condition (defined as a simple predicate) specifies the grid events that enable the reaction of a specific level of CCS. Different events or sequences of events can enable different reaction levels. The reaction delay models the overall computation and application time needed by CCS to apply a reconfiguration, which can be considered immediate for local decisions. The reconfiguration strategy $\mathcal{RS}$ defines how the configuration of EI changes when CCS reacts to a disruption. For each level, a different reconfiguration function is modeled:

- $\mathcal{RS}_1()$, to represent the effect on the complete transmission grid of the local and fast reactions to a disruption.
- $\mathcal{RS}_2()$, to represent the effect on the complete transmission grid of the global and slower reaction to a disruption.

Both these functions receive in input the state of the EI at the time immediately before the occurrence of the disruption and output the new values for $\mathbf{P}$ and $\mathbf{F}$, which are the result of the reaction of CCS to the disruption. The following simplifying assumptions are considered:

1) The output values of $\mathcal{RS}_1()$ and $\mathcal{RS}_2()$ for $\mathbf{P}$ and $\mathbf{F}$ satisfy the power flow equations (1), (2) and (3).
2) The reaction to a disruption represented by $\mathcal{RS}_1()$ is "worse" (from the point of view of the tradeoff between voltage quality and costs) than the reaction represented by $\mathcal{RS}_2()$, being $\mathcal{RS}_1()$ based on a local view of the state of the system and requiring $\mathcal{RS}_1()$ only a few seconds to react to a disruption.
3) The times to trigger $\mathcal{RS}_1()$ and $\mathcal{RS}_2()$ are $T_1 = 0$ and $T_2 \geq 0$, respectively.

The definition of the functions $\mathcal{RS}_1()$ and $\mathcal{RS}_2()$ depends on the policies and algorithms adopted by CCS. For a given load power demand, the power flow equations (1), (2) and (3) do not have a unique solution. There are many combinations of generator powers to satisfy a given load demand. In the standard approaches adopted in literature [7], [2], [16] the solution to this equations system is formulated as an optimization to minimize the change in generation or load shedding subject to the system constraints. Therefore, a possible definition of the function $\mathcal{RS}_2()$ is given by the solution (values for $\mathbf{P}$ and $\mathbf{F}$) of equations (1), (2) and (3) while minimizing the simple cost function:

$$C_2 = \sum_{i \in \mathcal{G}} |P_i - P_i^0| + W_L \sum_{i \in \mathcal{L}} |P_i - P_i^0|,$$

with the following constraints:

$$0 \leq P_i \leq P_i^{max}, i \in \mathcal{G}, \tag{5}$$

$$P_i^0 \leq P_i \leq 0, i \in \mathcal{L}, \tag{6}$$

$$-kF_l^{max} \leq F_l \leq kF_l^{max}, l \in \mathcal{F}, \tag{7}$$

where P_i^0 is the injected power immediately before the occurrence of the disruption that triggers $\mathcal{RS}_2()$. The parameter W_L is the cost for load shedding, which is set to an high value in order to force the generation dispatch first. The line overload parameter k represents either the risk of adverse reaction of CCS (when $k < 1$), or a risk of taking a reaction of CCS (when $k > 1$) [16]. In C_2, the cost to adjust the generators is the same and the loads have the same priority to be served. The function C_2 aims at performing the least possible modifications of the electric state of the grid, with respect to the electric state immediately before the occurrence of the disruption that triggered $\mathcal{RS}_2()$. Different cost functions can be considered for $\mathcal{RS}_2()$, such as:

$$C_2' = \sum_{i \in \mathcal{G}} |P_i - P_i^0| + W_L \sum_{i \in \mathcal{L}} |P_i - P_i^0| + W_z z,$$

with the following constraint added to previous ones:

$$-z \leq F_l \leq z, l \in \mathcal{F}.$$

This function minimizes a tradeoff between the change in generation, the load shedding and the maximum load through a line. The parameter W_z is the price for maximum load through a line. It can be set to a value such that $W_L >> W_z >> 0$ in order to force the reduction of the maximum load through a line before the generation dispatch, or to a value such that $W_z < 1$ (and $W_L >> 0$) in order to force the generation dispatch first. It is important to note that the definitions considered for $\mathcal{RS}_2()$ are based on the same optimization problems that can be solved (on-line or off-line, if possible) by CCS to react to a disruption. On the contrary, for defining $\mathcal{RS}_1()$ the algorithms adopted by CCS are not taken into account explicitly, but only their possible and supposed effects on the overall system are considered in terms of the solutions to the power flow equations (1), (2) and (3). A possible definition of the function $\mathcal{RS}_1()$ is given by the following steps:

1. For a given load power demand and distribution of generation $\mathbf{P}$, the solution $\mathbf{F}$ of equations (1), (2) and (3) is obtained, if it exists. In this case redispatch or load shedding are not needed, but the power flow through the lines increases and it can produce overload, especially if constraint (7) is not considered or if $K > 1$.

2. Otherwise (if redispatch or load shedding are required) the values for $\mathbf{P}$ and $\mathbf{F}$ are obtained solving the following optimization problem:

$$\min C_1 = C_2, \tag{8}$$

such that the power flow equations (1)-(3) and the constraints (5)-(7) are satisfied and

$$C_1 \geq \beta C_2^{min}, \tag{9}$$

where C_2^{min} is the minimum value of the cost function C_2 obtained solving (the optimization problem of) $\mathcal{RS}_2()$, and β, with $\beta \geq 1$, represents how much $\mathcal{RS}_1()$ is worse than $\mathcal{RS}_2()$, according to assumption 2).

An example of different definitions of $\mathcal{RS}_1()$ can be considered redefining the step 2. The values for $\mathbf{P}$ and $\mathbf{F}$ are obtained solving the following optimization problem:

$$F^{'} = \max_{l \in \mathcal{F}} \max_{h \in \mathcal{F}} |F_h W_h^F| \text{ s.t. } \max |F_l|, \tag{10}$$

such that the power flow equations (1)-(3) and the constraints (5)-(7) are satisfied. The parameter W_h^F is the weight (or cost) associated to each transmission line h. It can depend on the temperature of the medium T_0. The value of $F^{'}$ is equal to the maximum power flow which can go through a line. In accordance with assumption 2), this definition for $\mathcal{RS}_1()$ makes sense when the configuration, for which the power through a line takes the maximum possible value, is the worst one.

4.4 Failure model of CCS

Following the approach proposed in [15] for the hidden failure model of the protections, the probability $p^{HF}(P)$ that a protection fails is low when the power flow is below the component limit P^{CL}, and increases linearly to 1 when the component flow is 1.4 times the P^{CL}:

$$p^{HF}(P) = \begin{cases} p^{HF} & \text{if } P < P^{CL}, \\ \frac{1-P^{HF}}{0.4P^{CL}}P + \frac{1.4P^{HF}-1}{0.4} & \text{if } P^{CL} \leq P \leq 1.4P^{CL}, \\ 1 & \text{otherwise.} \end{cases}$$

Moreover, the hidden failure probability P^{HF} reduces to zero after the first exposure to disruption [15].

Failures of the CCS components are considered in the model, including transient and permanent omission failures, time failures, value failures and byzantine failures. Here the focus is on the failures and not on their causes (internal HW/SW faults, malicious attacks, etc.). The dependencies from EI to CCS (cascading failures) could be also considered, for example handling the case that a blackout shrinks the performance of CCS. In the current implementation only omission and timing failures of CCS are considered.

5 Measures of interest

The simulator supports the evaluation of dependability and performability measures of EPS, well representative of the behavior of the whole modeled infrastructure, as well as evolution of the electrical parameters along time. The main measures considered in the current implementation are:

- The expected reward $E[V_t]$ at time t, defined by:

$$V_t = \sum_{\mathbf{P} \in RS} \mathcal{R}(\mathbf{P}) I_t,$$

  where I_t is a random variable that is equal to 1 if the real injected power in the transmission grid at time t is $\mathbf{P}$, otherwise $I_t = 0$, and $\mathcal{R}(\mathbf{P})$ is the reward associated to the real injected power $\mathbf{P}$, where:

$$\mathcal{R}(\mathbf{P}) = \sum_{i \in \mathcal{G}} P_i W_i^G + \sum_{j \in \mathcal{L}} P_j W_i^L,$$

  with W_i^G and W_j^L the cost and the reward associated to generator i or load j, respectively.
- The expected reward $E[Y_{[0,t]}]$ accumulated in the interval $[0,t]$, with $Y_{[0,t]}$ defined by:

$$Y_{[0,t]} = \sum_{\mathbf{P} \in RS} \mathcal{R}(\mathbf{P}) J_{[0,t]},$$

  where $J_{[0,t]}$ is a random variable that represents the total time that real injected power has value $\mathbf{P}$ during the time interval $[0,t]$.
- The expected percentages of blackout B_t and $B_{[0,t]}$ at time t and in the interval $[0,t]$, respectively. This is a particular case of the previous ones.
- The expected numbers of components N_t and $N_{[0,t]}$ affected by a disruption at time t and in the interval $[0,t]$, respectively.

6 The architecture of the simulator

EPSyS has been structured in six main modules, as shown in Figure 1. Two of them (ECM and TM) reproduce

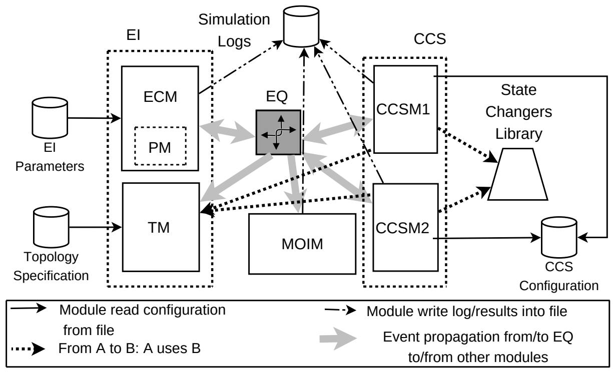

Fig. 1. Building blocks of the simulator.

the EI behavior. The module ECM implements the (electrical) state of the elements of the transmission grid and their failure model. ECM also includes the protection system (PM) embedded into EI, which triggers the automatic defensive actions after a disruption and the hidden failure model. The module TM implements the topology of the transmission grid represented by an oriented graph. The modules CCSM1 and CCSM2 implement the behavior of CCS at the two different abstraction levels considered. Both these components can be considered like an instance of a generic component CCSM, that supports the activation condition, the reaction delay, the reconfiguration strategy ($\mathcal{RS}$) and the failure model of CCS. CCSM1 and CCSM2 support the functions $\mathcal{RS}_1()$ and $\mathcal{RS}_2()$, respectively. If the activation conditions are met, the corresponding corrective actions are performed immediately by CCSM1 and within a reaction delay by CCSM2. The component EQ implements the events queue, which allows the whole power system model to evolve reproducing the dynamics of EPS. Finally, there is the module MOIM that supports the measures of interest.

EPSyS has been developed in Python (for high level code) and C (for low level, performance-critical code) languages.

7 The simulation procedure

The states of the EI are represented by the t-uple $(E_{i,h}, T_i)$, with $i = 1, 2, \cdots$, and $h = 1, 2$. T_i is the topology and $E_{i,h}$ represents the electrical state resulting from the application of the reconfiguration strategy $\mathcal{RS}_h()$ on the topology T_i. The main steps of a simulation run are:

1. For a given topology $\boldsymbol{A}$ and a given susceptance matrix $\boldsymbol{B}$, the initial setting for $\mathbf{P}$ and $\mathbf{F}$ can be derived manually or solving an optimization problem using the same approach adopted to evaluate the functions $\mathcal{RS}$. The initial state of EI is represented by $(E_{0,2}, T_0)$.
2. Values of the occurrence times of random disruptions (of EI and failures of CCS) are sampled from the distributions considered for the failure model.
3. When, in the state $(E_{i,2}, T_i)$, a random (or cascading) disruption is selected from the event queue, the following steps are performed with j=i+1:
4. The disruption immediately propagates to the neighbor components, based on the hidden failure model of the protections, generating a new topology T_j for EI.
5. The function $\mathcal{RS}_2()$ is evaluated, based on the electrical state $E_{i,2}$ and on the topology T_j.
6. The function $\mathcal{RS}_1()$ is evaluated, based on the electrical state $E_{i,2}$ and on the topology T_j. If the definition of $\mathcal{RS}_1()$ is based on the result of the optimization problem defined for $\mathcal{RS}_2()$, as shown in equation (9), the function $\mathcal{RS}_2()$ must be evaluated before $\mathcal{RS}_1()$.
7. The outputs $\mathbf{P}$ and $\mathbf{F}$ of $\mathcal{RS}_1()$ are immediately applied to EI (i.e., at the system time of the disruption occurrence), generating a new $E_{j,1}$ for EI.
8. The values of the occurrence times of cascading disruptions for the new state $(E_{j,1}, T_j)$ are sampled from the overloading failure model.
9. the value of the delay t_2^{RS} to the occurrence of the reconfiguration $\mathbf{P}$ and $\mathbf{F}$, obtained through the solution of $\mathcal{RS}_2()$, is sampled from the distributions considered for the CCS model.
10. When cascading or random disruptions occur (being selected from the event queue) before time t_2^{RS}, the simulation goes to step 4. with $j = j + 1$ (where the evaluation of $\mathcal{RS}_2()$ is restarted based on the new topology generated by the new disruption).

11. Otherwise, if no disruption occurred before t_2^{RS}, at time t_2^{RS} the outputs $\mathbf{P}$ and $\mathbf{F}$ of $\mathcal{RS}_2()$ are applied, generating a new state $(E_{j,2}, T_j)$ for EI.
12. The values of the occurrence times of cascading disruptions for the new state $(E_{j,2}, T_j)$ are sampled from the overloading failure model.
13. If an halting condition is satisfied (e.g, a total blackout, or a state without cascading and random disruptions, or when a pre-determined instant of time is reached), the simulation stops, otherwise the simulation goes to step 3.

Note that the functions $\mathcal{RS}_1()$ and $\mathcal{RS}_2()$ are evaluated on the states $(E_{i,2}, T_j)$, although alternative choices could be considered. Moreover, when cascading or random disruptions occur before time t_2^{RS} (step 10.), instead of restarting the evaluation of $\mathcal{RS}_2()$, different alternatives can be considered, such as performing immediate but less effective actions, or even do nothing.

8 Conclusions

This paper has presented the simulation models and the implementation of EPSyS, an ad-hoc simulator developed to analyze Electric Power Systems, considering the interdependencies existing between the two EPS subsystems (that is the Electric Infrastructure and the Computer-based Control Systems). The models adopted for the stochastic analysis of EPS, including the failure models of the transmission grid and of the CCS, have been described in detail, as well as their implementation.

The core of EPSyS consists in the definition of proper structures to represent the EI infrastructure and the electrical parameters, and in the two algorithms adopted by CCS to perform reconfiguration as reaction to EI disruptions (implemented as local and global reaction, respectively). This clear distinction at level of CCS reconfiguration policies has been operated to properly account for different reaction time to disruptions. In particular, the local reaction is considered instantaneous, while the global one has a reaction time assigned, since it needs time to gather information from a number of sites of the EPS infrastructure and to process them to take a reaction decision. This approach is in line with what happens in real situations, and on this aspect it constitutes an advancement wrt to existing solutions.

An experiments campaign is currently in progress, where EPSyS is used to analyze the behavior of a portion of the IEEE 118 Bus test Network [19] under several EI disruption conditions. The results of this testbed scenario will be made available soon.

Acknowledgments

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