OPERATIONAL PLANNING OF POWER SYSTEMS INCLUDING SMALL-SIGNAL STABILITY ENHANCEMENT CONSIDERATIONS

J. L. Rueda[1], W. Guamán[2], I. Erlich[1], A. Vargas[2], D. G. Colomé[2]

[1]Institute of Electrical Power Systems - University Duisburg-Essen
Bismarckstr. 81, 47057 Duisburg, Germany. Phone: +49 203 3795051, Fax: +49 203 3792749
E-mail: jose.rueda@uni-duisburg-essen.de, istvan.erlich@uni-due.de

[2]Institute of Electrical Energy – National University of San Juan
Av. Lib. San Martín 1109 (o), 5400 San Juan, Argentina. Phone: +54 264 4226444, Fax: +54 0264 4210299
E-mail: guaman@iee.unsj.edu.ar, avargas@iee.unsj.edu.ar, colome@iee.unsj.edu.ar

Abstract– Operational planning of power systems, especially in terms of overall reliability and security, is facing increasing requirements and challenges because of deregulation and restructuring processes of electricity markets in many countries across the world, which have resulted in greater competition and the development of new market structures for trading electrical energy. Therefore, it is necessary to develop new strategies to cope with increasing uncertainties arising from the fast changing ways power systems are being operated. In this paper, a comprehensive approach to determine an optimal transmission network expansion plan considering the enhancement of small-signal stability is presented. The dynamic model of the transmission network expansion planning is solved based on combination of a meta-heuristic evolutionary algorithm, a heuristic procedure and the classic dynamic programming method. Besides, probabilistic eigenanalysis is employed to determine the transmission plans that are highly relevant to the enhancement of the system small-signal stability performance. Numerical results demonstrate the viewpoint and the effectiveness of the proposed approach in providing optimal strategies of minimum cost while avoiding the instability risk associated to poorly damped low-frequency electromechanical oscillations.

Keywords: Competitive markets, transmission expansion planning, hybrid solution, optimal investment sequence, small-signal stability, Monte Carlo method, probabilistic eigenanalysis

1 INTRODUCTION

The key goal of operational planning is to determine when and where to incorporate new equipment to meet both operational and economical criteria. Here short-term and medium-term horizons (up to 10 years) would be encompassed [1]-[2]. To date, according to the current practice in many countries worldwide, the transmission network expansion planning (TNEP) can be carried out either by i) a transmission company based on an indicative plan of generation and approved by a regulator entity, ii) a group of agents and subject to approval from a regulator entity, or iii) the regulator entity. The first and the third modalities are also known as centralized transmission expansion planning, but the former has been widely adopted in some Latin American countries like El Salvador, Panama, Brazil, Colombia and Peru.

Traditionally, TNEP studies have mainly implied the assessment of limits associated with static constraints (e.g. thermal limits) as well as some dynamic constraints such as large disturbance rotor angle stability (i.e. transient stability), voltage stability, and frequency stability whereas, by contrast, there has been no strict adherence to the small-signal stability constraint. Nevertheless, because of the changing ways power systems are being operated in the new power industry deregulated environment, solving the TNEP problem involves much greater uncertainties related to several factors, such as load forecast, availability of system components, transmission expansion costs, fuel availability and costs, bidding strategies, to name a few, which also entail an increased degree of occurrence of system disturbances. Moreover, within this context, several recent studies have shown that troublesome low-frequency electromechanical oscillations (LFEOs) may become the limiting factor for secure power system operation [3], thus indicating the relevance of system stability in TNEP studies. This factor is especially critical in weakly meshed power systems, where the stability is predominantly a problem of insufficient damping for LFEOs [4].

Mathematically, the TNEP problem corresponds to a non-linear non-convex mixed integer optimization problem because it includes non-linear functions, real and integer variables. There is very little literature related to the solution of the dynamic model of the TNEP due to the high complexity involved [5]. Alternatively, several approaches have been proposed based on simplified static and multistage models as well as on local correlation network patterns, classic optimization, heuristic and meta-heuristic methods in order to reduce the computational effort [5], [6].

The work contained in this paper provides a comprehensive approach to determine an optimal transmission network expansion plan considering the enhancement of small-signal stability. The approach contains four stages: i) Static planning in the last year of the short-term planning horizon is solved by using an evolutionary particle swarm optimization (EPSO) algorithm; ii) Classical dynamic programming is then applied to tackle the timing optimization problem of determining the committed year of transmission lines that are part of the transmission plan. Solving the timing optimization problem presents a formidable challenge since it contains a high number of possible states and optimal paths. This drawback is overcome by using a heuristic algorithm that is based on the right-of-ways associated to overloaded operating conditions; iii) the small-signal stability performance of the system under each feasible expansion plan is examined by means of probabilistic eigenanalysis; iv) selection of the most suitable plan by contemplating the fulfillment of the small-signal stability constraint and minimum-cost criterion.

The remaining part of the paper is organized into the following sections: Section 2 gives an overview of the proposed approach, discussing the main issues associated with spatial and timing optimization problems, and probabilistic eigenanalysis. In Section 3, a test case is developed and evaluated. Finally, conclusions and outlook for future work are drawn in Section 4.

2 PROPOSED APPROACH

The framework of the proposed approach is sketched schematically in Fig. 1. The procedure starts with the definition of the models required for power system steady-state and dynamic analysis (i.e. actual system model), the indicative plan of generation, technical and economical data as well as the stochastic modeling of input system variables. Next, a set of feasible expansion alternatives in the last year of the operational planning horizon (e.g. short-term) are determined through an optimization problem solved by an EPSO algorithm. Multiannual transmission network expansion plans in the predefined planning horizon (e.g. up to 5 years for the short-term [2]) are then determined based on classical dynamic programming combined with a heuristic algorithm. Next, for each expansion plan, probabilistic eigenanalysis is employed to assess the instability risk associated to LFEOs and to enhance the system damping performance based on a probabilistic index for suitable power system stabilizer (PSS) device location. Besides, coordinated tuning of PSSs is performed based on fuzzy clustering and the formulation of an optimization problem, solved by an EPSO algorithm. Finally, the selection of the most suitable expansion plan among the least cost-low small-signal instability risk plans is accomplished.

2.1 Stochastic modeling of demand and fuel prices

It is widely known that mean-reverting stochastic processes certainly constitute reasonable and plausible ways to replicate the uncertain evolution over time of fuel prices as well as the demand growth rate. A mean-reverting process is characterized by a fluctuating evolution of stochastic paths around a known long-run mean [7]. In this paper, the stochastic model of the demand growth rate is represented by [8]:

$$x_t = x_{t-1}e^{\eta\Delta t} + \bar{x}\left(1 - e^{-\eta\Delta t}\right) + p_1 \quad (1)$$

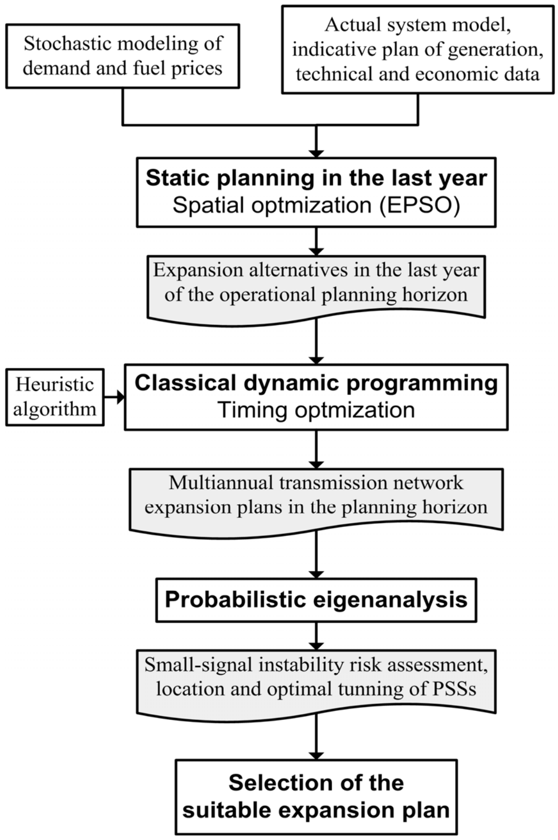


Figure 1: Framework of the proposed approach

The stochastic simulation of coal and gas prices is carried out through (2) whereas the mixed Poisson-Gaussian (or simply jump-diffusion) stochastic process, according to (3) and (4), is used to model the evolution of the oil price [8]:

$$p_t = e^{\ln(p_{t-1})e^{-\eta\Delta t} + \ln(\bar{p})\left(1-e^{-\eta\Delta t}\right) - \left(1-e^{-2\eta\Delta t}\right)\frac{\sigma^2}{4\eta} + p_1} \quad (2)$$

$$p_t = e^{z_t - 0.5\,\mathrm{var}(z_t)} \quad (3)$$

$$z_t = z_{t-1}e^{\eta\Delta t} + \ln(\bar{p})\left(1 - e^{-\eta\Delta t}\right) + p_1 + \mathrm{jumpsp} \quad (4)$$

where

$$p_1 = \sigma\sqrt{\frac{1 - e^{-2\eta\Delta t}}{2\eta}}\,N(0,1) \quad (5)$$

x_t, z_t and p_t are the values corresponding to the demand growth rate, the normal level of fuel prices and the fuel price at time t, x_{t-1}, z_{t+1} and p_{t-1} are the values corresponding to the demand growth rate, the normal level of fuel prices and the fuel price at time t-1, $\bar{x}$ and $\bar{p}$ are the mean values of the demand growth rate and the fuel price in the short-term run, var(x_t) is the variance of x_t, Δt is the discrete time sub-period (in years) in which the short-term planning horizon is divided, η is the reversion rate of x or p, σ is the volatility of x, jumpsp are the jumps modeled through the Poisson process, and N(0,1) is the standard normal distribution with zero mean and unit variance.

2.2 Static planning in the last year

The mathematical model for the spatial optimization problem in the last year of short-term planning horizon considering a predefined indicative plan of generation, the expected values of nodal demands around highly loaded conditions and fuel prices, and using the DC model, presents the following format:

Minimize

$$c_{\mathrm{v}} = \frac{1}{(1+\mathrm{I})^{\mathrm{t_c}}}\left[\sum_{(\mathrm{i,j})\in\Omega} c_{\mathrm{ij}} n_{\mathrm{ij}} + \sum_{\mathrm{j}\in\Omega} co_{\mathrm{j}}(g_{\mathrm{j}}) g_{\mathrm{j}} + c_{\mathrm{r}} \sum_{\mathrm{k}\in\Gamma} r_{\mathrm{k}}\right] \quad (6)$$

subject to

$$\mathbf{Sf} + \mathbf{g} + \mathbf{r} - \mathbf{d} = 0 \quad (7)$$

$$f_{\mathrm{ij}} - \gamma_{\mathrm{ij}}\left(n_{\mathrm{ij}}^{\mathrm{o}} + n_{\mathrm{ij}}\right)\left(\theta_{\mathrm{i}} - \theta_{\mathrm{j}}\right) = 0 \quad (8)$$

$$\left|f_{ij}\right| \le \left(n_{\mathrm{ij}}^{\mathrm{o}} + n_{\mathrm{ij}}\right) f_{\mathrm{ij}}^{\max} \quad (9)$$

$$0 \le g_{\mathrm{j}} \le g_{\mathrm{j}}^{\max} \quad (10)$$

$$0 \le r_{\mathrm{k}} \le d_{\mathrm{k}} \quad (11)$$

$$0 \le n_{\mathrm{ij}} \le n_{\mathrm{ij}}^{\max} \quad (12)$$

n_{ij} integer, θ_{j} unbounded

where c_{v} is the present value of the total sum of expansion and operating costs, I is the discount rate, $\mathrm{t_c}$ is time of the cash flow, c_{ij} represents the cost of a circuit that can be added to the i-j right-of-way, n_{ij} is the number of circuits added to the i-j right-of-way, $n_{\mathrm{ij}}^{\mathrm{o}}$ is the number of circuits in the base case, $n_{\mathrm{ij}}^{\max}$ is the maximum number of circuits that can be added to the i-j right-of-way, co_{j} is the annual operating cost of the j-th generation unit, g_{j} is an element of the vector **g**, and represents the generation level at bus j whose maximum value is $g_{\mathrm{j}}^{\max}$, **d** is the vector of nodal power demands, γ_{ij} is the susceptance of a circuit in the i-j right-of-way, **S** is the branch-node incidence transposed matrix, f_{ij} is the power flow in the i-j right-of-way and represents an element of the vector **f**, $f_{\mathrm{ij}}^{\max}$ represents the maximum power flow in the i-j right-of-way, θ_{i} is the voltage angle at bus i, c_{r} is a financial factor for load shedding, r_{k} represents the load shed at the k-th bus due to a deficit in transmission capacity and represents an element of the vector **r**, Ω is the set of all right-of-ways, and Γ is the set of buses where the load shedding is considered.

Constraint (7) models the first law of Kirchhoff whereas constraint (8) is an expression of the second law of Kirchhoff. Constraint (9) enforces the line flow limits, whereas constraints (10) and (11) impose bounds on generation level and load shedding, respectively. Finally, constraint (12) represents the maximum number of circuits that can be added to the i-j right-of-way. The mathematical model (6) – (12) can be solved using some settled mathematical optimization techniques such as heuristic algorithms, classic methods and meta-heuristics. In this paper, an EPSO algorithm, whose theoretical background is presented in [9], is used, since it constitutes a powerful solver when applied to complex problems as demonstrated in several applications related to the power engineering field.

2.3 Classical dynamic programming

Having determined the set of expansion alternatives in the last year of the operational planning horizon, the next task is to determine the optimal investment sequences throughout the whole planning horizon in order to obtain multiannual transmission plans that entail minimum-cost alternatives (i.e. timing optimization). In this paper, the timing optimization problem is solved through classical backward dynamic programming (i.e. a technique that is well suited to solve problems where is necessary to define a sequence of decisions in an interrelated manner). To solve the dynamic TNEP problem, the total planning horizon (e.g. short-term) is bifurcated into sub-periods or time intervals, each of which is one year long. Then, the basic idea is to consider the timing optimization problem as a multi-stage or multi-period sequential decision process wherein the optimal strategies thereof are recursively calculated. Thus, recursive formulation for the multi-period TNEP problem can be expressed as

$$\mathrm{f}_{\mathrm{n}}^{*}(s) = \min_{x_{\mathrm{n}}}\left[c_{s_{\mathrm{n}}} + \mathrm{f}_{\mathrm{n+1}}^{*}(x_{\mathrm{n}})\right] \quad (13)$$

where $\mathrm{f}_{\mathrm{n}}^{*}(s)$, $c_{s_{\mathrm{n}}}$ and $\mathrm{f}_{\mathrm{n+1}}^{*}(x_{\mathrm{n}})$ denotes the total cost of investment and operation associated to the s-th state or configuration in the n-th sub-period, immediate cost in the n-th sub-period, and future minimum cost associated to the n+1 sub-period, respectively. x_{n} is the decision variable given by transmission line investments in the n-th sub-period.

To find the optimal sequence, it is required to analyze a considerable number feasible paths and states derived from possible combinations among the transmission lines determined in the spatial optimization, which indeed would involve a substantial computational burden. Nevertheless, since dynamic programming constitutes an optimization strategy rather than a closed algorithm, it allows easy incorporation of complementary routines (e.g. subordinate heuristic procedures) during the optimization process with the premise of reducing the number of states and of feasible paths to be evaluated by the planner. Thus, a heuristic algorithm, which accounts for the fulfillment of the maximum allowable transmission power, is incorporated during the optimization process. The heuristic algorithm has the structure shown in Fig. 2. Firstly, the s-th network configuration at n-th sub-period is evaluated at the subsequent n+1sub-period via optimal power flow (OPF) calculation in order to assess the fulfillment of the maximum allowable right-of-way power limit. If there is more than one overloaded right-of-way, a new circuit will be added to the right-of-way with the largest absolute value of the overload percentage index $\mathrm{I_{op}}$ defined as

$$I_{op} = 100 * \frac{P_{actual}}{P_{limit}} \quad (14)$$

where P_{actual} and P_{limit} are the actual active power flow and the maximum allowable active power flow through of the i-j overloaded right-of-way.

OPF calculation is performed again to assess the suitability of the adapted configuration and the process is repeated successively until overloading is relieved. This procedure is coupled with a second one in which the right-of-way loading level is decreased below its P_{limit} in a similar fashion. Using this integrated process at every successive sub-period to go from one definite configuration at the initial time to the optimal configuration at the last year, a reduced set of feasible multiannual transmission plans, which ensure operating conditions within specified P_{limit}, are obtained.

2.4 Probabilistic eigenanalysis

It is worth mentioning that, as depicted in Fig. 1, this subsequent stage is not embedded in the optimization process. The flowchart of the Monte Carlo based-probabilistic eigenanalysis is illustrated in Fig. 3 [10]. The procedure starts with the definition of the models required for power system dynamic analysis, the probabilistic models of system input variables (i.e. probability distribution functions of nodal loads and mean values of the coefficients defining piecewise quadratic cost functions of generating units) and the requirements for small-signal stability performance (e.g. damping ratio threshold imposed on the system by the small-signal security constraint in order to guarantee secure operation).

Next, for each system configuration to be evaluated, samples of nodal demands are generated according to their probability distribution function models. Based on a settled utility's operating policy to balance power (e.g. least-cost or merit-order economic dispatch), a set of generation variables corresponding to each set of sampled nodal demands is obtained (i.e. all components of the input nodal vector are obtained). Each trial input vector defines an operating state which is determined by power flow calculation. Viable operating states that fulfill steady state voltage limits, thermal overloading of transmission elements, and maintain the generation units operating within their limits are then selected.

The system small-signal stability performance is then evaluated via modal analysis for each viable operating state. Here, critical modes, their associated frequency, damping ratio , mode shapes and participation factors are calculated. An eigenvalue tracking procedure based on modal parameters is also applied at this stage to ensure proper storage of modal analysis information and to ensure proper statistical evaluation of computed critical mode parameters. Besides, sequential estimation of statistical relative error is applied in probabilistic eigenanalysis in order to ensure a high degree of confidence. Thereafter, based on the resultant statistics, the probabilistic indexes R_{Inst} and DE_{PSS} are calculated to assess the instability risk due to negatively damped or lowly damped oscillatory modes (OMs) and to provide useful information for small-signal stability performance enhancement by means of suitable PSS location. Based on a defined threshold (e.g. $_i$ >10%), the R_{Inst} index is calculated accounting the cumulative probability distribution function (CPDF) associated to each critical mode as follows

$$R_{Inst} = \begin{cases} OM_{\zeta\text{-Neg}} = P(\zeta_i < 0) \\ OM_{\zeta\text{-Poor}} = P(0 \le \zeta_i < 5\%) \quad i = 1, \cdots, M_C \\ OM_{\zeta\text{-Damp}} = P(\zeta_i \ge 5\%) \end{cases} \quad (15)$$

Where $OM_{\text{-Neg}}$ indicates the probability of instability due to negatively damped OM, $OM_{\text{-Poor}}$ indicates the probability associated to poorly damped OM, and $OM_{\text{-Damp}}$ indicates the probability associated to well damped OM. M_C is the number of critical modes, and P(.) means cumulative probability.

Considering different critical modes separately, and through the analysis of the histograms of the participation factors, the DE_{PSS} index is computed for each mode according to:

$$DE_{PSSi} = \max_{k=1 \cdots N_G} \left\{ E\left|pf_{\Delta\omega}\right|_k \right\} \quad (16)$$

where the suffix i denotes the i-th mode, N_G is the number of generators, $E|pf_{\Delta w}|$ is the mean of the participation factor (PF) associated with the generator speed deviation states (Δw). DE_{PSS} constitutes a suited measure since it implies that adding a PSS at the k-th generator will affect the damping of the i-th mode under multi-operating conditions.

Next, a combined technique of subtractive clustering and fuzzy c-means algorithm is applied to select a reduced subset of scenarios (i.e. amongst the whole number that was analyzed across Monte Carlo based-probabilistic eigenanalysis) by similarity judgment according to the statistical properties of their attributive features (e.g. system loading conditions, modal properties) [10]. Subsequently, tuning of rotor speed deviation input - PSSs is performed by solving the following optimization problem [9]:

$$\min OF(\mathbf{x}) = \sum_{k=1}^{nc} \sum_{i=1}^{nm} \sum_{j=1}^{ng} (1 - p_{ij}) K_j \quad (17)$$

subject to

$$|\Delta f_i| \le \Delta f_{threshold} \quad (18)$$

$$\zeta_i \ge \zeta_{threshold} \quad (19)$$

$$\mathbf{x}_{j-min} \le \mathbf{x}_j \le \mathbf{x}_{j-max} \quad (20)$$

where **x** is the set of parameters of each PSS, K_j is PSS gain of the j-th generator, p_{ij} is the normalized speed PF of the j-th generator in the i-th OM, nc is the number of selected scenarios, nm is the number of OMs, ng is the number of generators, f_i and ζ_i denotes mode frequency and damping, respectively. Constraints (18) and (19) impose bounds on maximum tolerable mode frequency deviation and minimum acceptable mode damping ratio, respectively.

2.5 Selection of the suitable expansion plan

The costs and the small-signal stability performance of each multiannual transmission plan are compared, and hence the least-costly-low small-signal instability risk plan is selected as the most suitable one.

3 TEST CASE STUDY

Numerical experiments were performed on a HP Pavilion dv3 PC with Intel (R) Core (TM) 2 CPU, 2.2 GHz processing speed, and 4 GB RAM. The modeling, load flow, and modal analysis were accomplished by several routines written in Matlab which utilize some modified functions of the Power System Analysis Toolbox (PSAT) [11]. The QR method is used for full eigenvalue computation. The proposed approach is tested using the well known two area – four machine system (TAFM) [12]. The single line diagram of the system, including future network expansion resulting from short-term planning, is depicted in Fig. 4. It consists of two similar areas connected through two long tie transmission lines. The tie transmission lines are relatively weak because of their distance of about 110 km. Each area has two thermal power plants. The generators are modeled using the subtransient model and equipped with fast static exciters and simple thermal turbine-governors. Only generators 1 and 4 are equipped with PSSs in the actual (baseline) system configuration in which the system exhibits three OMs: one inter-area mode, in which the generating units in Area 1 (G1 and G2) oscillate against those in Area 2 (G3 and G4), and two local modes, one in each area, associated with the oscillations of the generating units within each area. Static and dynamic data of the system in the baseline configuration can be found in [12].

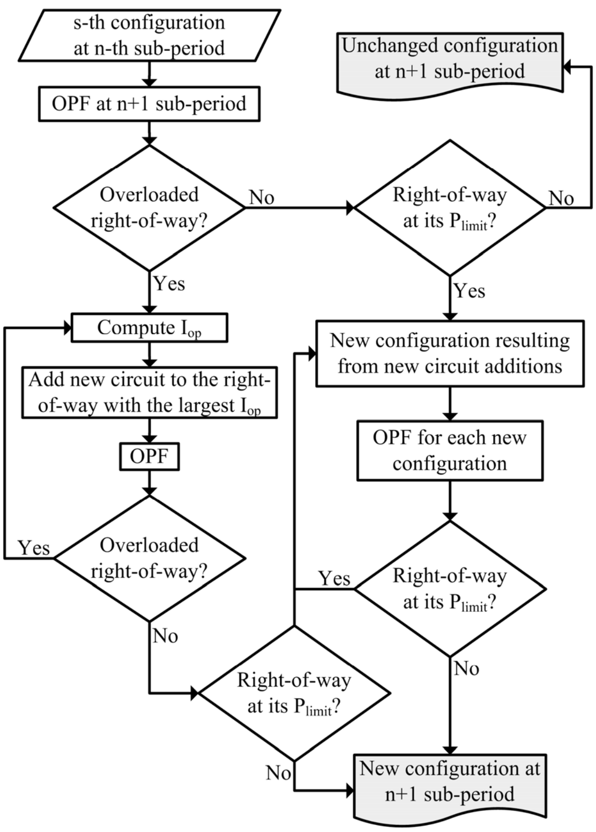


Figure 2: Heuristic algorithm embedded in the dynamic programming technique

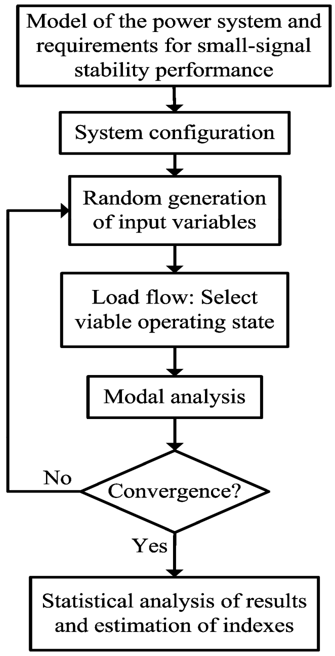


Figure 3: Monte Carlo based-probabilistic eigenanalysis

The indicative plan of generation (which is generally known beforehand) illustrated in Fig. 5(a), includes future incorporation of fuel-oil and gas generating units. The set of parameters describing random deviations of nodal demand growth around the expected values of the annual highest load demand in peak hours, which are commonly assumed to be normally distributed according to the Central Limit Theorem – by following the stochastic model formulated in (1) [11], is shown in Fig. 5(b) whereas the mean values of the coefficients defining piecewise quadratic cost functions of generating units, which were determined by following the stochastic models formulated in (2) - (5) (i.e. based on existing information about historical as well as forecasting data on costs and prices [5]), are omitted here for sake of brevity. Also, from Fig. 4 and Fig. 5(b), note that new load is connected at bus 101 from year 1.

3.1 Results from spatial and timing optimization

As discussed in Sub-section 2.2, the spatial optimization problem (6) - (12) is firstly solved to determine a set of expansion alternatives in the last year of the short-term planning horizon. It has 43 variables (14 of them are integer variables) and the mean CPU time for applying EPSO was approximately 15 min. Table 1 gives the results for two feasible expansion alternatives, comparing the present values of the total sum of expansion and operating costs (c_v) as well. Based on these results, and by resorting to the procedure described in Sub-section 2.3, the second step is to determine the optimal investment sequence throughout the whole planning horizon in order to obtain a multiannual transmission plan for each alternative. Results are summarized in Table 2. It can be seen that, from a purely static planning viewpoint, plan 1 is the one of lowest cost. By contrast, from a multiannual economic perspective, plan 2 is the one of minimum total cost, since it is the cheapest that manages to fulfill the greater demand while allowing more power to be harnessed from the cheaper generators G1 and G2 and significantly decreasing operating costs throughout the whole planning horizon. The resulting optimal investment sequence of plan 2 is illustrated in Fig. 6. It merits mentioning that 33 states (derived from possible combinations among the transmission lines determined in the spatial optimization) would have had to be analyzed by the planner to determine the optimal sequence. However, when the heuristic algorithm was considered, the number of states was decreased to 7 (i.e. which would provide more suitable investment strategies). Hence, overall CPU time required for timing optimization was 4 min. Moreover, timing optimization was performed 100 times in order to evaluate the confidence level. It was found out that in most of the cases (i.e. 97 optimization runs), the same results were always obtained.

3.2 Results from probabilistic eigenanalysis

In this paper, it is considered that the system has sufficient damping when the critical modes have $\geq 10\%$ for all operating conditions, including operating conditions following system element outages. The purpose of this criterion is to ensure that, in small-secure operating conditions, no OM in the system has a damping ratio less than the specified threshold [10]. For the baseline configuration in both plans, preliminary probabilistic eigenanalysis revealed an inter-area mode with frequency ranging from 0.51 Hz and 0.57 Hz, and two local modes with frequencies around 1 Hz. Besides, for all three modes, is greater than 10 % in all simulated operating states, and hence they are not considered a threat to system security at this stage. Overall CPU time for probabilistic eigenanalysis with 5835 trials was 48.04 min.

New transmission lines (i.e. one in the case of plan 1 and two in the case of plan 2) and generator G6 are added to the system to meet the increased demand at year 1. The values for the three possibilities of R_{Inst} index, considering only PSSs at G1 and G4 from baseline configuration and without considering new PSS addition, are illustrated in Table 3 for both expansion alternatives at this period. Note that both plans exhibit small-signal instability risk associated with the occurrence of poorly damped inter-area and G6 local oscillations. The risk is considerably higher for plan 1. This is reasonable since the increase in demand results in increased exports from G1 and G2 and in higher power flows over the tie lines, which would deteriorate the system damping performance. By contrast, the situation is significantly less critical in plan 2, since the addition of a new transmission line between bus 3 and bus 101 would relieve congestion on the existing tie lines which is also highly desirable from the viewpoint of small-signal stability. For both plans, damping of G6 local mode can be improved by adding a PSS to that unit, whereas damping of the inter-area mode can be improved by readjustment of existing PSSs at G1 and G4. Coordinated tuning of all three PSS, which is performed by solving the optimization problem formulated in (17) - (20), has proved to be sufficient for improving the system damping performance to the required damping ratio threshold.

Similarly, for both plans, probabilistic eigenanalysis is used to evaluate the damping performance of different system configurations derived from further expansion alternatives in the subsequent periods. The set of necessary remedial measures that were determined by resorting to the procedure described in Sub-section 2.4 is illustrated in Fig. 7. In any of both plans, it can be seen that readjustment-coordinated tuning would go on for subsequent periods. Also, note that for plan 1 it would be necessary to further add PSSs at G2 and G3 (according to the DE_{PSS} index) at year 2 and year 3, respectively, to fulfill the system damping performance requirement. By contrast, only an additional PSS at G2 would be needed for plan 2, which would indeed involve lower extra costs. Finally, an observation of the above-described results indicates that, taking economical and small-signal stability factors into account, plan 2 yields the best overall performance.

4 CONCLUSIONS

This paper presented a comprehensive approach to determine an optimal transmission network expansion plan considering the enhancement of the system small-signal stability performance. The dynamic model of the TNEP is mainly evaluated by performing static planning in the last year of the short term planning horizon through an optimization problem solved by an EPSO algorithm, multiannual timing optimization through classical dynamic programming combined with a heuristic algorithm, and probabilistic eigenanalysis analysis in a complementary manner. The results obtained using a benchmark weak interconnected power system comprising conventional thermal power plants distributed in two areas and exhibiting both congestion and stability problems demonstrate the benefits of the proposed approach. Remarkably, it can provide a deeper look into the small-signal problems facing different transmission expansion plans. Since the proposed methodology is to be performed off-line, there is not, in principle, a severe restriction on computation time. Nevertheless, in the reference studies, computational effort has been questioned as bottleneck for probabilistic eigenanalysis of large-scale power systems. The main reasons have been limitations of computational resources and lack of powerful eigenvalue computation algorithms. However, some recent publications present suitable approaches for fast eigenvalue computation of large-sized interconnected power systems, i.e. a parallel variant of Arnoldi method [13] and methods of computational intelligence [14]. Furthermore, additional computational gains can be obtained with the use of grid computing [15]. The approach can be extended to further developments and improvements considering more uncertainties such as component availabilities, other technical factors such as voltage stability, frequency stability and fault currents, and the addition of HVDC links and FACTS devices (which may include supplementary power oscillation damping controllers).

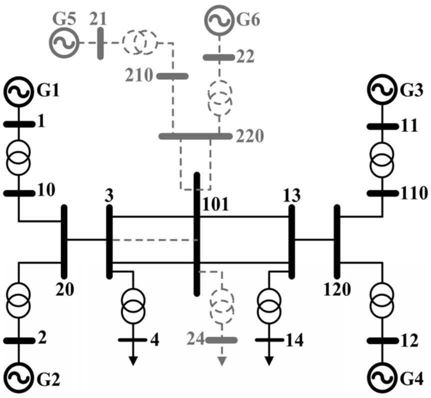
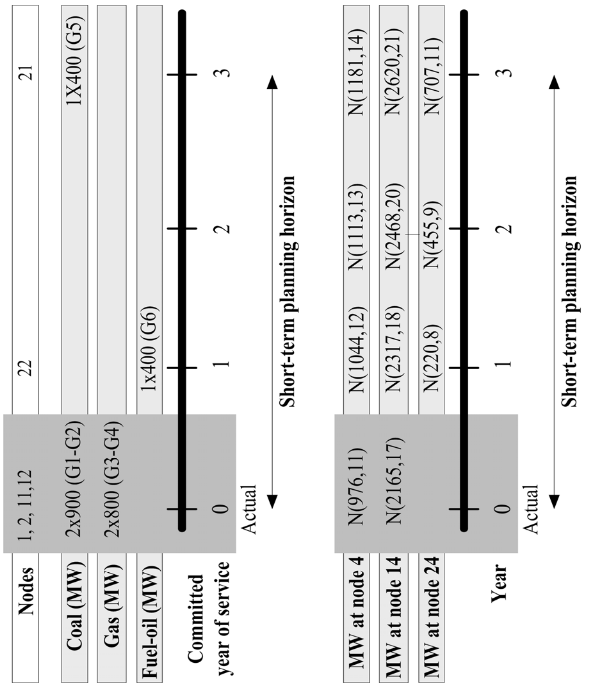


Figure 4: Single line diagram of the TAFM. The actual (baseline) system configuration is depicted with solid black lines whereas future network expansion is highlighted with gray solid and dashed lines



(a) (b)

Figure 5: Short-term indicative plan of generation (a), and nodal demand growth (b). N(μ,σ) indicates normal distribution with mean parameter μ and standard deviation parameter σ

	Alternative 1	Alternative 2
New TL	2x(101,220) 1x(210,220)	1x(3,101) 2x(101,220) 1x(210,220)
c_v **($)**	916,712,754	949,591,803

Table 1: Set of expansion alternatives in the last year of the planning horizon. TL stands for acronym for transmission line. (*i*,*j*) denotes the right-of-way between bus *i* and bus *j*

	Spatial optimization		Timing optimization	
	c_v **($)**	**Rk**	**Total cost ($)**	**Rk**
Plan 1	916,712,754	1	1,944,431,856	2
Plan 2	949,591,803	2	1,917,154,250	1

Table 2: Costs and ranking (Rk) of the multiannual transmission plans

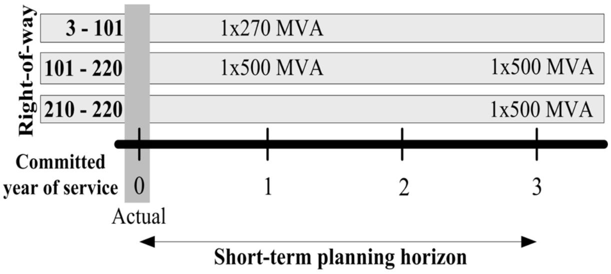


Figure 6: Optimal investment sequence of plan 2

		R_{Inst}		
	Mode	**OM** $_{-Neg}$	**OM** $_{-Poor}$	**OM** $_{-Damp}$
Plan 1	IA1	0.00	0.12	0.88
	LOC1	0.00	0.00	1.00
	LOC2	0.00	0.00	1.00
	LOC3	0.00	0.09	0.91
Plan 2	IA1	0.00	0.07	0.93
	LOC1	0.00	0.00	1.00
	LOC2	0.00	0.00	1.00
	LOC3	0.00	0.04	0.96

Table 3: R_{Inst} index at year 1. IA1 denotes the inter-area LFEO G1-G2 vs. G3-G4, LOC1 denotes the local LFEO G1 vs. G2, LOC2 denotes the local LFEO G3 vs. G4, and LOC3 denotes the local LFEO of G6 against the system

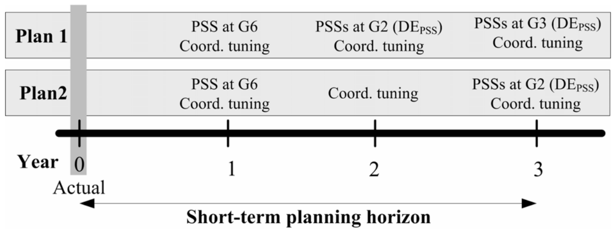


Figure 7: Small-signal stability remedial measures throughout the short-term planning horizon

REFERENCES

[1] J.F. Alonso, A. Sáiz, L. Martín G. Latorre, A. Ramos, and I.J. Pérez-Arriaga, "PERLA: An Optimization Model for Long Term Expansion Planning of Electric Power Transmission Networks", IIT-91-009 Jan. 1991.

[2] J.I.R. Rodriguez, D.M. Falcão, and G.N. Taranto, "Short-term Transmission Expansion Planning with AC Network Model and Security Constraints", 16th PSCC, pp. 1 – 7, Glasgow, Scotland, July 2008

[3] Z. Huang, N. Zhou, F. Tuffner, Y. Chen, D. Trudnowski, W. Mittelstadt, J. Hauer, and J. Dagle, "Improving small signal stability through operating point adjustment", IEEE Power and Energy Society General Meeting, pp 1 – 8, 2010.

[4] E. Allen, A. Keri, A. DeGroff, D. Kosterev, and P. Tatro, "Importance of dynamic stability phenomena in power system planning", IEEE Power & Energy Society General Meeting, pp 1 - 6, 2009

[5] L. Garces, and R. Romero, "Specialized Genetic Algorithm for Transmission Network Expansion Planning Considering Reliability", 15th International

Conference on Intelligent System Applications to Power Systems, pp 1 - 6, 2009

[6] J. H. Zhao, J. Foster, Z. Y. Dong, and K. P. Wong, “A statistical approach to transmission network expansion planning”, 8th International Conference on Advances in Power System Control, Operation and Management, pp 1 - 8, 2009

[7] G. Blanco, “Valuation of Flexible Investment Portfolios in Transmission System including FACTS devices”, Ph.D. dissertation, National University of San Juan, Argentina, 2010

[8] M. A. Guimarães, “Stochastic processes with focus in petroleum applications: Monte Carlo simulation of Stochastic Processes”, Industrial Engineering Department, Pontifícia Universidade Católica do Rio de Janeiro [Online]. Available: http://www.puc-rio.br/marco.ind/sim_stoc_proc.html

[9] V. Miranda, “Evolutionary Algorithms with Particle Swarm Movements”, Proceedings of the 13th International Conference on Intelligent Systems Application to Power Systems, pp 6 - 21, 2005

[10] J.L. Rueda, “Assessment and enhancement of small signal stability of power systems considering uncertainties”, Ph.D. dissertation, National University of San Juan, Argentina, 2009

[11] F. Milano, L. Vanfretti, and J.C. Morataya, “An Open Source Power System Virtual Laboratory: The PSAT Case and Experience”, IEEE Transactions on Education, vol. 51, no. 1, pp 17 - 23, Feb. 2008

[12] G. Rogers, “Power system oscillations”, Boston, Kluwer Academic Publishers, 2000

[13] I. Erlich, and A. Fischer, “Fast assessment of small-signal oscillatory stability in large interconnected power systems”, Balkan Power Conference BPC, pp. 343-348, Yugoslavia, June 2002

[14] S.P. Teeuwsen, I. Erlich, and M.A. El-Sharkawi, “Small-signal stability assessment for large power systems using computational intelligence”, IEEE Power Engineering Society General Meeting, Vol. 3, pp. 2661 – 2668, June 2005.

[15] Z. Xu, M. Ali, Z.Y. Dong, and X. Li, “A novel grid computing approach for probabilistic small signal analysis”, IEEE Power Engineering Society General Meeting, June 2006, pp. 1 - 8.