Electrical Power and Energy Systems 63 (2014) 917–926

Contents lists available at ScienceDirect

Electrical Power and Energy Systems

journal homepage: www.elsevier.com/locate/ijepes

Computationally efficient composite transmission expansion planning: A Pareto optimal approach for techno-economic solution

Neeraj Gupta, Rajiv Shekhar *, Prem K. Kalra

Department of Materials Science & Engineering, Indian Institute of Technology Kanpur, India

ARTICLE INFO

Article history:
Received 13 March 2013
Received in revised form 26 May 2014
Accepted 27 May 2014
Available online 23 July 2014

Keywords:
Transmission expansion planning
Generation planning
Genetic algorithm
Congestion management
Social welfare
Linear matrices

ABSTRACT

This paper presents an integrated approach for composite transmission expansion planning incorporating: (i) computationally efficient linear matrices, (ii) a novel Demand/Energy Not Served (DNS/ENS) and Generation Not Served (GNS) calculation approach, to circumvent the time intensive iterative procedures. A self-tuning mechanism based on stochastic Roulette Wheel (RW) simulation procedure supports the reduction of network congestion. It establishes a trade-off between technical and economic criteria using the theory of marginal value (marginal reduction in interruption cost and marginal increment in the investment) for the incremental updating method. A hybrid of deterministic (N-1) and probabilistic (critical N-2) contingency scenarios have been simulated for security of the system. Results show that existing lines and generators capacity are necessary to update for economic operation for minimizing interruption cost and to achieve optimal investment. Modified 5-bus 24-bus and 118-bus IEEE systems are taken to show the generalization of methodology.

Introduction

During the last few decades, rapid changes in the electricity industry around the globe necessitate a robust and optimal transmission infrastructure to supply electricity. The existing literature provides a wide variety of TEP methodologies in the complex deregulated environment [1,2], where, very few technical papers have discussed composite TEP (generation and transmission planning are carrying simultaneously) [3,4]. The methodologies developed for TEP can be classified according to different domains such as (i) modeling, (ii) optimization method, (iii) reliability, (iv) congestion management, (v) AC power planning, (vi) competition and electricity market, (vii) uncertainty analysis, (viii) distributed generation (integration of wind farms and other renewable generators), (ix) environmental impact (x) Coordinated TEP and composite TEP, and (xi) security constrained TEP. A comprehensive review is presented in [1–10]. Some researchers have used above described domains separately in TEP [1–9], however, rarely integrated – even at some extent – on a single platform [9]. In this regard, a number of technical papers and reports have discussed the transmission system planning issue as a set of optimization problems [1–8,10–14], where variables are discrete, for example, capacity of generators and lines, location of lines, etc. [10–13]. Over the last two decades, numerous articles and books have been written on the development of search techniques for optimizing TEP, focusing on both traditional (linear, quadratic programming, mix-integer, heuristic, etc.) and non-traditional optimization techniques (GA, swarm, meta-heuristic, etc.) [1–13]. Using these techniques, TEP has, over the years, evolved from cost-based to value-based approaches [9–14]. In the value-based approach, Min-cut-max-flow (MCMF) algorithm and load flow based curtailment strategy have been used to calculate expected demand/energy not served (EDNS/EENS) [1,3,8,12], as reliability measures. The iterative computational requirement of EDNS/EENS forced planners to find a novel, simplified non-iterative approach [1,12,14]. An analytical review of TEP models and reliability measures are given in [1,15]. The TEP methodology given in [15] demonstrates a new non-iterative EDNS/EENS calculation approach, which might be useful in the long term TEP procedure with MCS based probabilistic contingency analysis. Here minimization of the sum of investment, operational and interruption costs were carried out to determine optimal TEP [1–15]. Most of the research papers in this regard have used deterministic N-1 contingency based TEP methodology, while very few publications have reported work based on N-2 and MCS based contingency approach [1,12,15].

Developing countries such as India are going through a rapid change of industrial development process, resulting in a large demand. India plans to install 74 GW generation capacity by 2017 [16]. Clearly, increase in generation capacity has to be

* Corresponding author. Tel.: +91 (512) 259 7016.
E-mail address: vidtan@iitk.ac.in (R. Shekhar).

http://dx.doi.org/10.1016/j.ijepes.2014.05.070
0142-0615/

complemented with increased transmission capacity. Moreover, electric power systems are getting more and more complex due to bottlenecks in transmission networks, primarily because of uncertain demand growth and increased heterogeneity of power generation processes [1,14]. The Central Electricity Regulatory Commission (CERC) in India has estimated that 10.3–12.9% power deficit is due to unreliable transmission network [16,17], which, in turn, may also increase the risk of blackouts Thus, a robust and optimal transmission infrastructure to supply electricity reliably is of prime importance under smart operation of the power industry. This, in turn, requires analysis of more severe contingency scenarios other than N-1 contingency scenarios, especially in a country such as India where demand far outstrips supply [1,12,14,18]. Along with, it should attract the investors for a huge investment by giving them profit maximizing signal [4], where loss should be minimum due to contingency and congestion in the network. This motivates us to propose a techno-economic computational efficient planning methodology (incorporating demand and probabilistic outage of lines), which incorporates reliability evaluation modeling [7,12,13,19], congestion management criterion [12], uncertainty analysis, security of the systems, value assessment [12], and market based approach [3,16].

The TEP approach followed by previous investigations has several shortcomings [1–22]. First, the capacity of all possible new alternative lines and generators were specified *a priori* (only locations have been selected during the optimization process). Second, the calculation procedure of ENS (DNS) is iterative, thus expensive to implement with probabilistic contingency analysis. Third, transmission service provider's and generator's benefits are not incorporated simultaneous with customer's profit in the concept of social welfare, for example, non-zero ENS also implies unutilized generation capacity or generation not served (GNS) and wheeling loss (WL), the cost of which must be accounted for in TEP. Fourth, the computational efficiency of the algorithm should be better to analyze sever probabilistic contingency scenarios along with N-1 contingency scenarios. Fifth, the techno-economic planning criteria are rarely available for the composite planning of generators and transmission network, which results excessive investment. Six, generally during the planning of the power systems, reliability level is decided "*a priori*" based on experts knowledge. Thereafter, simulation is carried out to achieve least cost solution satisfying the decided reliability level. Selection of reliability level does not have any analytical procedure, which may leads to sub-optimal solution. In the proposed methodology, well known and globally accepted "Marginal cost" based approach is demonstrated to trade-off reliability (least interruption cost) and economics (least investment) [16].

Unfortunately, the proposed TEP in [12] is computationally-intensive. For a modified IEEE-5 bus power system, it takes seven days (calculation is processed on Computer E-series (VPCEC15FG), 2.13 GHz, 4 GB ram) to give an optimal solution for a case study incorporating 450 GA iterations with 30 population size, twelve demand scenarios, and 1000 MCS contingency scenarios. A similar exercise for a 24-bus IEEE power system takes more than 14 days. To make it computationally efficient, linear sensitivity factors have been incorporated: (1) GPF (generation participation factor) to replace the iterative ELD calculation [23], (2) PTDF (power transfer distribution factor) matrix to replace multiple DC-load flow calculations [24], (3) LODF (Line outage distribution factor) and GLODF (generalized line outage distribution factor) matrix for transmission lines contingency analysis [25], and (4) BBIM (bus-branch incidence matrix) [16,26] for the calculation of ENS and GNS. The overall scheme is implemented on the modified IEEE-5 bus, IEEE-24 bus and IEEE-118 bus test power systems to show the generalization at large networks. Here, Eq. (8) is used (constrained by Eq. (7)) to establish a better trade-off between economics and reliability [16]. The proposed methodology finds an optimal solution by using the marginal cost (investment) theory [16].

Methodology

The proposed methodology has been implemented with the following assumptions:

(a) Forecasted peak hourly load curve at all buses is defined to incorporate 8760 seasonal scenarios [16].
(b) Single-stage planning of 10 years is demonstrated [12].
(c) 8.5% Compound load growth is selected for target year [12].
(d) Probabilistic N-2 contingencies are incorporated along with N-1 contingency scenarios.
(e) Location of generators and possible candidate alternative lines are pre-specified based on topological conditions, expert knowledge and resource availability [16].
(f) Old generators and transmission lines are free to update with new capacities, which are to be calculated by the planning procedure.
(g) Demand is assumed completely elastic and variation of 20% is permitted from mean value over the year [16].

Objective function

The objective function (J) includes sum of operational cost, interruption cost (cost of expected ENS, GNS, WL, and outage cost of generation), and investment for setting up the new lines and generation capacities.

$$J = \Bigg(\underbrace{\sum_{t=1}^{8760} \Big(C_{EENS}(t) * EENS(t) + C_{EGNS}(t) * EGNS(t) + C_{EWL}(t) * EWL(t) + \sum_{s \in g} C_{rl,s} * EGO_s(t)\Big)}_{\text{Interruption cost w.r.t customer, generators, transmission owner}} + \underbrace{\sum_{q=1}^{N_T} C_{T1,q} * TL_q + \sum_{p=1}^{N_n}\left(\sum_{t=1}^{8760} C2_{T,p} * OCF_{T,p} * TL_p * F_p\right)}_{\text{Investment and operating cost in setting up transmission lines}} + \underbrace{\sum_{s=1}^{g}\left(C1_{G,s} + \sum_{t=1}^{8760} C2_{G,s} * OCF_{G,s}\right)(EPG_s - EG_s)}_{\text{Investment and operating cost in setting up generation capacity}} \Bigg) \quad (1)$$

Subscript T stands for transmission line and G stand for generator, where t is the time at which quantities are measured. EENS, EGNS and EWL represents expected energy not served (MWh), expected