Electric Power Systems Research 116 (2014) 36–44

Contents lists available at ScienceDirect

Electric Power Systems Research

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

Transmission expansion via maximization of the volume of feasible bus injections☆

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ARTICLE INFO

Article history:
Received 8 February 2014
Received in revised form 5 May 2014
Accepted 10 May 2014
Available online 28 May 2014

Keywords:
Bilateral/multilateral transaction
Effective resistance
Graph theory
Laplacian embedding
Resistance distance
Transmission expansion planning

ABSTRACT

The predicted turnover in North America's fleet of electric generation, and the diverse sources (e.g., natural gas, nuclear, coal, wind, photovoltaic, solar thermal) suggests great uncertainty in both type and geographic location of the future generation mix. This presents huge challenges to existing methods in transmission expansion planning that rely on assembly of detailed scenarios for assumed types and locations of future generation and load growth. As a fundamentally different philosophy, this paper seeks a quantitative measure of transmission system performance that is intrinsic to the network itself. In particular, we examine the impact of network expansion on the generalized volume of bus power injections feasible under line flow. Using the standard construct of the dc power flow approximation, this paper demonstrates that such a measure is easily defined analytically. From knowledge only of the base case network's bus susceptance matrix, the approaches in this paper yield computationally efficient algorithms for siting and sizing transmission links: line siting and sizing via minimization of line effective resistance and maximization of the volume of feasible power injections. While a wide range of other policy, environmental, and engineering issues will remain important to transmission planning, the methods here will enhance planning by providing quantitative ranking of candidate network additions with respect to overall transmission system performance. The algorithms are illustrated for the IEEE 300-bus test system.

1. Introduction

Analysis strategies and algorithms for optimal transmission expansion planning in electric power networks have traditionally been closely tied to assumed scenarios of generation expansion and load growth. Typical strategies might seek transmission additions that meet a short/long-term demand need, while addressing reliability issues at the lowest feasible cost. In some regions, economic factors are allowed to be considered independent of reliability, and objectives might reflect market outcomes in light of transmission enhancements, enabling access to lower cost generation and/or facilitating energy transactions between market participants [1].

However, the literature in transmission expansion research that has emerged in the 21st century reflects a growing consensus that traditional analysis methods may be inadequate to address the great uncertainties in generation and market allocation of power transfer [2–5]. As one direction for improved transmission planning, stochastic recourse methods have been proposed as a means to capture timing characteristics of transmission/capacity expansion decisions, in which intermediate decisions, partially through the multi-year planning horizon, can influence and/or impose constraints on future decisions [3]. Work in [6], proposes a two-stage stochastic approach to the transmission planning problem, with implementation via Benders decomposition techniques. Similarly, motivated by the uncertainty of transmission systems enhancements needed for generation facilities in a deregulated environment [7–9], formulate a three-level model that takes into account both transmission and generation investment decisions, drawing on the initial approach developed by [10]. Nonetheless, even these more sophisticated approaches have employed a number of possible generation and load growth scenarios that are modest when compared to the enormous combinatoric number of possible future changes to the system, in generation, load, and network facilities. As an example of the current state of the art in industry practice, consider the 2013 Western Electricity Coordinating Council (WECC) interconnection-wide planning activities,

☆ This work is sponsored through a contract from Argonne, a U.S. Department of Energy Office of Science Laboratory, and was supported by the Applied Mathematics Activity, Advanced Scientific Computing Research Program within the DOE Office of Science.

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http://dx.doi.org/10.1016/j.epsr.2014.05.004
0378-7796/

conducted by the Transmission Expansion Planning Policy Committee (TEPPC), and reported in [1]. These planning studies evaluated a specified set of "futures" (i.e., scenarios) over a 10 and 20-year planning horizon. Adopting similar philosophy, another comprehensive regional study over the whole U.S. Eastern Interconnect attempted to capture the range of possibilities in transmission line siting using eight overall futures, varied over seventy-two sensitivities [11,12].

The premise of the work here is that in the U.S. and many other regions, credible scenarios for future generation are tremendously uncertain, with a huge number of plausible cases for geographic locations, sizes and types of generation that may be added in the coming decades. While perhaps less extreme than generation, the specifics of load growth also display great uncertainty, particularly if the impact of new technologies such as plug electric vehicles are considered.

In light of the uncertainty in future generation and load, approaches that assume a modest number of specified scenarios to inform transmission expansion decisions may not be adequate. As an alternative, the work to be presented here will develop transmission performance metrics that are intrinsic to the network itself, without dependence on specific generation and load scenarios. Within the power systems literature, several works have adopted a similar general philosophy, seeking to develop a numeric measure of grid flexibility, and have included this flexibility measure within an overall multi-objective optimization strategy [13]. Other work [14] has examined siting of substations using graph concepts of node-centrality, which also shares the characteristic of design based on characteristics inherent to the network. The approach here, while related in general concept, adopts a very different numeric measure that characterizes several key electrical performance properties of the transmission network. The approach of this paper is inspired in part by results appearing in the literature on optimal routing algorithms for data networks. There also, a full optimal solution to the network routing design problem would be very dependent on specific probability distributions for data generated or consumed over huge numbers of nodes. However, like the power grid problem, presuming detailed knowledge of patterns of data, even probabilistically, is often unrealistic and/or intractable. In that literature, an approach that has garnered attention goes by the title of "oblivious" routing [15,16]. These routing strategies optimize an objective depending only on the network structure itself, without information on distributions of nodal data production or consumption. Hence, the algorithm may be said to be "oblivious" to the distribution of nodal data. The approach proposed here shares this general strategy: we propose performance metrics for an electric power transmission network that are independent of specific generation/load placement scenarios, but instead use, measures that seek to maximize the network's ability to absorb and deliver power.

2. The classic transmission expansion planning problem formulation

TEP decisions typically formulate an optimization problem subject to constraints reflecting operational reliability and environmental factors. While a distinction is made between reliability versus economically driven transmission expansion in the regulatory area, we claim that this distinction lies in the attention given to particular motivating aspects of the problem, rather than in the underlying mathematical formulation. For reliability driven expansion studies, one often presumes scenarios in which the base system configuration becomes infeasible with respect to operational constraints that are critical to reliability. In this context, the primary focus is on identifying enhancements that guarantee feasibility with respect to reliability constraints. Clearly, however, even when identifying transmission enhancements to ensure reliability, one will seek to do so while considering the associated capital and operational cost. Conversely, in those cases for which transmission expansion may be viewed as economically motivated, the base case configuration may have the property that it remains feasible (with respect to reliability constraints) over the future load growth scenarios, and one looks for transmission enhancements primarily to lower cost. However, it is clear that feasibility constraints reflecting operational and reliability limits remain enforced when seeking to solve a problem of this type. In light of these observations, we will seek to describe typical formulation of the problem (albeit simplified), consistent across either reliability-driven or economically-driven transmission expansion.

The optimization problem of interest is generally carried out over a range of scenarios that attempt to characterize credible future economic conditions (e.g., fuel prices), generation additions and retirements, and load changes for the planning horizon under consideration [17].

To solve large-scale, long-time horizon network constrained production-costing problems, a number of software packages have evolved in the power industry; including PROMOD and GE's Multi-Area Production Simulation Software (GE MAPS) [18,19]. The recent regional planning study supported by the U.S. Department of Energy, the EIPC (Eastern Interconnection Planning Collaborative), illustrates common use of such tools. That study began from a Phase I in which 72 "sensitivities" (i.e., details of geography-specific load growth and generation additions) were identified; these were grouped in eight overall "futures" (i.e., assumptions on economic growth, and energy prices) to define the range of scenarios that were examined. As reported in [20], GE MAPS software was employed to examine each of these scenarios, with the underlying analysis being a security constrained optimal power flow, with unit commitment, performed on an hour-by-hour basis for a ten to twenty-year planning horizon.

To set the stage for the alternative here, it is worthwhile to revisit the hierarchy of optimization problems of the type used in EIPC. At the lowest level is a security constrained optimal power flow (OPF). Recall that a standard OPF problem assumes a known, fixed set of generators available and "on-line" for a relatively short time interval of interest (e.g., one hour), and minimizes per hour production cost while meeting operational and security constraints.

Next in the hierarchy is the multi-time period unit commitment problem that selects exactly which set of generators should be on-line within any individual one hour period, while considering inter-temporal costs and constraints such as startup costs and minimum run time for generators. Long-term production costing is then essentially a unit commitment problem extended to a multi-year period, evaluated over the multiple scenarios of interest.

In order to direct attention on the issues of importance here, and to keep the necessary notation tractable, we will focus on the two ends of the hierarchy described above: the optimal power flow problem at the shortest time interval of interest (e.g., one hour), and the selection of transmission expansion scenarios at the long time horizon (illustrated here as ten years). In particular, the illustrative problem formulation below will not encompass the unit commitment, instead treating the set of available generators as known for each hour, and will neglect inter-temporal constraints or costs. Likewise, the illustration will display only one pattern of load change over time. Because the ultimate goal is a formulation that eliminates the need for detailed, explicit characterization of generation additions/retirements or patterns of load change in the transmission planning problem, it is hoped that this simplified illustration of the basic optimization will prove adequate to motivate the new approach to follow.

Consider a classically formulated OPF problem for a power system network. Let $\mathcal{N} = \{1, 2, \ldots, n\}$ represent the set of all buses,