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A two-stage stochastic programming approach for reliability constrained power system expansion planning

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A B S T R A C T

Probabilistic realizations of outages and their effects on the operational costs are highly overlooked aspects in power system expansion planning. Since the effect of randomness in contingencies can be more prominent especially when transmission switching is considered, in this paper we introduce contingency-dependent transmission switching concept to ensure N-1 criterion. To include randomness of outages and the outputs (i.e. flow on the lines/generation amounts) during the outages, we represent each contingency by a single scenario. Status of transmission lines, generation amounts and power flow decisions are defined as recourse actions of our two-stage stochastic model, therefore, expected operational cost during the contingencies are taken into account in a more accurate manner. A solution methodology with a filtering technique is also proposed to overcome the computational burden. The model and the solution methodology are tested on the IEEE Reliability Test System and IEEE 118-bus power system and the results show that the solution method finds the solutions for these power systems in significantly shorter solution times. The solution method is also tested on a new data set for the 380-kV Turkish transmission network. Suggestions for possible extensions of the problem and the modifications of the solution approach to handle these extensions are also discussed.

1. Introduction

Power system expansion planning determines the least costly expansion plan by locating new generation units and transmission lines. Generation expansion planning (GEP), a problem in which the location, capacity and time of building new power plants is determined [1–4], and transmission expansion planning (TEP), a problem that optimizes the design of a network by selecting the location, capacity and time of building new transmission lines [5–7] have been studied in this field. Generation-transmission expansion planning (GTEP) problem uses the interconnected nature of GEP and TEP problems (i.e. capacity and location of a new generation plant is affected by the available capacity of transmission lines) to simultaneously optimize them. For more information on the different modelling approaches and solutions techniques refer to [8,9].

Reliability constrained GTEP (R-GTEP), another problem commonly studied in literature, defines reliability as the ability to withstand disturbances arising from outage of generation units or transmission lines [10]. The problem determines the new investments to guarantee that the system remains feasible in case of a component break-down (whole system load can still be met). Most of the studies that consider reliability criteria plan new investments based on only the feasibility of the power system after a line or generator contingency and ignore the outcomes during the contingency states [11–16]. As the probabilistic realizations of outages are customarily overlooked, the effect of randomness in contingencies on the investment plans and the cost of the expansion plans are usually disregarded. Some studies partially consider the probabilistic realization of outages by considering loss of load probability (LOLP) and/or expected energy not served (EENS) in the system [17–22] or risk-based decision-making process [23,24]. Although these studies consider the effect of randomness in contingencies on the investment costs, they still overlook the effect of probabilistic nature of contingencies on the operational costs. Reliability of power system has been also discussed considering different sources of uncertainties such as uncertainty in generation or consumer behavior of electricity price [25–27]. However, these studies also do not explicitly include the operational costs during the contingency states.

The role of randomness in outages in the power system expansion planning can be more prominent especially when transmission switching (TS) is considered. TS identifies the branches that should be taken out of service to change the topology of the system in order to increase the utilization of the network, decrease the total cost in the system and prevent the overloads on the transmission lines [28]. Beneficial impact of TS on the reliability and market efficiency of power system has been

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Nomenclature

- *Indices*

i, j	nodes (buses)
a	transmission lines (including types)
g	generators
k	operating states: $k = 0$ no-contingency state, $k = k_a$ contingency state with outage of line a

- *Sets*

B	set of all nodes (buses)
EG	set of existing generation units
CG	set of candidate generation units
G	set of all generation units, $G = EG \cup CG$
NG	set of all non-flexible generators, $NG \subset G$
EA	set of existing lines
CA	set of candidate lines
A	set of all lines, $A = EA \cup CA$
AS_{ij}	set of lines between nodes i and j
$\Psi^{+}(a)$	sending-end node of line a
$\Psi^{-}(a)$	receiving-end node of line a
K	set of contingencies/scenarios

- *Parameters*

l_i	demand of node i (MW)
$\overline{F_a}$	capacity of line a (MW)
$\overline{G}_{ig}$	maximum generation from unit g in node i (MW)
$\underline{G}_{ig}$	minimum generation from unit g in node i (MW)
c_g^{inv}	annualized inv. cost of unit g (\$)
c_g^{om}	operation cost of unit g (\$/MW h)
cf_g	capacity factor of unit g
c_a^{line}	annualized inv. cost of line a (\$)
φ_a	susceptance of line a (p.u.)
σ_a	forced outage rate of line a
Γ_a^k	1, if line a is on under contingency k, 0, if it is off
p^k	probability of contingency k
dur	duration of the planning horizon

- *Decision variables*

X_{ig}	1 if unit g is built at node i, 0 o.w.
P_{ig}^k	generation of unit g in node i under contingency k.
L_a	1 if line a is built, 0 o.w.
S_a^k	1 if line a is closed under contingency k and 0, if it is open
f_a^k	power flow on line a under contingency k
θ_i^k	voltage angle of node i under contingency k

demonstrated in academic studies as well as industrial applications. In [29,30], the authors discuss the congestions and cost savings of TS for the PJM system for different voltage levels changing from 115 kV to 765 kV. Furthermore, in [31], examples from California ISO, Independent System Operator of New England and PJM demonstrate that some protocols for switching transmission lines are applied for decreasing congestion, maintenance scheduling or seasonal switching.

The value of TS is also discussed for theoretical examples as in [32–35]. In [32], the authors use switching operations in expansion planning problem and discuss the effect of TS on expansion planning decisions. In [33], the value of a seasonal transmission switching on the total cost and reliability level of the power system is discussed and in [34], short-circuit current limitations for a power system considering TS and N-1 reliability criterion is analyzed. In [35], the authors analyze the effect of TS on the power system and they calculate the monetary value of EENS for the solutions and discuss the effect of TS on EENS. However, most of the studies determine the status of transmission lines before observing the contingencies and network topology is designed to satisfy the whole system load after any contingency without requiring operator control on generators. This approach is referred to as *preventive security constrained transmission switching* [35], and ignores the probabilistic nature of outages and the expected operational costs during the contingencies. Therefore, the overall costs of the investment planning projects are underestimated. Although having a single network topology for all time periods is extremely unlikely due to uncertainties [31], system operators have flexibility to monitor and change the status of the transmission lines after a contingency.

Considering the operational costs during the contingency states and changing the network topology for each contingency can affect the reliability of the power system and the investment plans significantly. Especially for power systems that have flexible generators, after a line or generator outage, corrective actions such as changing the outputs of the flexible generators and network topology by switching transmission lines can be taken to address the contingency [36]. Thus, over investments (i.e. building new generation units to supply only peak loads) can be prevented and utilization of the system can be increased. For this purpose, we introduce a new transmission switching concept, *contingency-dependent TS*, which entails the definition of transmission switching decisions based on each contingency. This concept is made possible by means of our two-stage stochastic programming model where the power flows, status of transmission lines and the generation amounts are defined as recourse actions. As generation amounts for each contingency state can be different from each other, the expected value of the operational costs of during the contingency states are taken into account in a more accurate manner.

Literature utilizes different approaches to overcome computational burden of the R-GTEP problem such as determining a short list of the candidate lines [12,13], line outage distribution factors (LODFs) method [14,15], worst case analysis [16] and umbrella constraint discovery (UCD) technique [37,38]. This paper presents a computationally tractable solution approach that includes a filtering to find the contingencies that do not affect the power system's reliability. This solution approach decreases the number of contingencies considerably and temporarily eliminates the constraints related with that contingencies. A similar notion is also used in UCD technique discussed in [37,38] to identify redundant constraints in security-constrained optimal power flow (SCOPF) and security-constrained unit commitment (SCUC) problems, respectively. Although the benefits of UCD technique is verified on both problems, it is discussed that the proportion of non-umbrella constraints in SCUC is lower compared to the proportion of non-umbrella constraints in SCOPF. Since our problem is structurally closer to the SCUC problem, and includes more binary variables in nature (i.e. decisions for the investment planning and switching transmission lines for each contingency) than the binary variables in SCUC problem, in this study, we utilize a filtering approach to find the critical contingencies. Thus, by using the filtering approach, we reduce the computational challenge of the two-stage stochastic programming model and find the optimal or near-optimal solutions for the original problem that satisfies the N-1 reliability criterion.

This paper proposes a two-stage stochastic programming model for the R-GTEP problem that minimize investment and expected operational costs. Our two-stage stochastic model represent each contingency state by a single scenario with a probability of happening and includes operational costs during the scenarios in the expected form. The main contributions of this paper are listed below:

- We propose a two-stage stochastic programming model for the R-GTEP problem that includes expected operational cost during the