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Flexible implementation of power system corrective topology control

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ABSTRACT

This paper proposes a novel decision making framework for optimal transmission switching satisfying the AC feasibility, stability and circuit breaker (CB) reliability requirements needed for practical implementation. The proposed framework can be employed as a corrective tool in day to day operation planning scenarios in response to potential contingencies. The switching options are determined using an efficient heuristic algorithm based on DC optimal power flow, and are presented in a multi-branch tree structure. Then, the AC feasibility and stability checks are conducted and the CB condition monitoring data are employed to perform a CB reliability and line availability assessment. Ultimately, the operator will be offered multiple AC feasible and stable switching options with associated benefits. The operator can use this information, other operating conditions not explicitly considered in the optimization, and his/her own experience to implement the best and most reliable switching action(s). The effectiveness of the proposed approach is validated on the IEEE-118 bus test system.

1. Introduction

Bulk electric transmission systems have been traditionally characterized with static assets and fixed configuration over time except in the cases of faults and forced outages. Power system topology control, often called transmission switching, offers the system operators an opportunity to harness the flexibility of the transmission system topology by temporarily removing lines out of the system. By changing the way how electricity flows through the system, transmission switching can be employed either in emergency scenarios (to alleviate violations, congestions, and overloading conditions), or during normal operating conditions (for higher economic benefits). Such considerations, which are employed in the operational time frame, make it possible to have more efficient use of the existent network facilities.

Though being performed for decades on a very limited scale with rather focused aims, transmission switching has recently gained further importance with the increased penetration of renewable energy resources and the growing demand for more reliable operation of power systems [1]. It has been shown that various operating conditions can be resolved through transmission switching; amongst, one can mention voltage violations and overloading conditions as a result of possible contingencies [2–4], network losses and congestion management [5,6], security enhancement [7,8], reliability improvements [9], and also cost reduction for economic benefits [10,11].

Reference [12] thoroughly reviewed the existing literature as of the late 1980s and introduced the transmission switching as a corrective mechanism in response to possible contingencies. A branch and bound optimization to handle the linear approximate optimal power flow (OPF) problem for corrective switching actions was also introduced in the late 1980s [13]. Optimal transmission switching, as a mixed integer programming (MIP) problem, based on the DCOPF formulation through which considerable economic savings may be gained, has been analyzed recently in [14]. Transmission switching as a corrective mechanism both with continuous and discrete control variable formulations is addressed in [15]. Flow canceling transactions in order to develop a MIP-based framework for system topology control were used in [16]. Some practical requirements for implementation of topology control applications in real world scenarios are generally introduced in [17]. Some of the mentioned approaches are too computationally intensive to find

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Nomenclature

A. Sets

$g \in G$	system generators
$g \in \dot{G}$	generators out of service due to a contingency
$k \in K$	system transmission lines
$k \in \hat{K}$	transmission lines in service
$k \in \bar{K}$	transmission lines out of service
$k \in \dot{K}$	out of service lines due to a contingency
$n \in N$	system buses

B. Decision variables

P_g	power output of generator g
P_k	power flow through line k
s_k	switch action for line k (0: no switch, 1: switch)
θ_n	bus angle at bus n
u_n	unfulfilled demand at bus n

C. Parameters

B_k	susceptance of line k
$B^t(\mathrm{RD}_i)$	incremental benefits obtained via generation re-dispatch-only at node i of the switching tree at time t
$B^t(S_i)$	incremental benefits obtained through successful implementation of switching line i and corresponding generation re-dispatch at time t
c_g	linear generation cost of generator g
d_n	demand (in MW) at bus n
$\mathrm{FP}^t(\mathrm{B}_i)$	failure probability of the CB i at time t
$MB^t(S_i)$	mean benefits obtained through successful implementation of switching and generation re-dispatch at node i of the decision tree at time t
M_k	big M-value for line k
$P^t(S_i)$	availability index of switching line i at time t
$P_k^{\max}, P_k^{\min}$	max. and min. line flow limit for line k
$P_g^{\max}, P_g^{\min}$	max. and min. generation limit for generator g
$\theta^{\max}, \theta^{\min}$	max. and min. bus angle difference
τ	minutes between two switching operations

the solutions fast enough for practical implementations. Some others do not simultaneously consider the control over the network topology and the ability to re-dispatch generation.

Advanced optimization techniques have been recently proposed to determine the transmission switching plans for day to day operations. In [18], heuristics to deal with the optimal switching problem in large-scale power systems are proposed. Fast transmission topology control heuristics in which expert's judgments are exploited in a DCOPF formulation to deal with the global marginal cost of congestion are proposed in [19]. Two fast heuristics for optimal transmission switching, one dealing with a sequence of linear programs (LPs) and the other with a sequence of MIPs taking one line out at a time, have been proposed in [20]. A fast efficient heuristic which selects the switching plan based on the minimum generation cost objective is proposed in [21]. The N-1 reliability criterion is integrated into the DCOPF formulation for the purpose of switching decision making in [22]. Topology control for load shed recovery (LSR) via the DCOPF-based MIP Heuristics (MIP-H) is recently proposed in [23].

An approach to incorporate the transient stability constraints in the ACOPF is proposed in [24] and controlling system stability through line switching is tested on an actual system in [25]. Likewise, for the transmission switching algorithms based on DCOPF formulations to be of practical use, one needs to ensure the AC feasibility and stability of the switching solutions. Reference [26] introduces the concept of robust corrective topology control and presents methodologies for real-time, deterministic planning-based, and robust corrective switching actions. The optimization procedure in [26] provides one switching sequence and involves repetitive solution of transmission switching optimization until a valid switching plan satisfying the AC feasibility and stability is found. However, if the selected lines are not switchable due to the associated circuit breaker (CB) failures, the switching process stops and the operator may need to re-run the optimization engine to obtain a new switching sequence. In practice, line switching implementation involves several operational procedures and clearances at various levels of the utility organizations which are commonly time consuming. So, transmission operators need to be provided with switching plans with high probability of success to minimize the involved time and labor. To the best of the authors' knowledge, none of the existing topology control algorithms address such practical considerations.

Trying to bridge the gap between the theoretical advancements in previous literature and the practical requirements that the operator will have to deal with, this paper proposes an implementation procedure for realizing transmission switching in practice. The main objective of this paper is to demonstrate how such technologies can empower the operator not only to obtain feasible switching actions, but also allow the operator to use his/her experience and personal judgment to decide which feasible set of actions to implement. The proposed framework, to be used in day to day operation planning scenarios in response to probable contingencies, provides several switching options per contingency in a tree-like structure. At each level of the switching tree, the framework suggests the operator a set of AC feasible and stable switching plans based on a selected optimization criterion such as maximum LSR or minimum generation cost, etc. This paper also proposes a decision making support tool based on a CB reliability assessment technique using condition monitoring data. A mean benefit index is proposed to quantify the impacts of failed CBs associated with switching of a transmission line in any substation configuration. The operator can use this information, other operating conditions not explicitly considered in the optimization, and his/her own experience to select the most reliable switching actions at each level of the tree for implementation. It is important to mention that the suggested switching actions will be a temporary solution to recover from the critical contingencies in a timely manner and the switched lines would be returned back to service when the contingency is permanently mitigated.

The rest of the paper is structured as follows. The proposed framework including the optimization algorithm to obtain the switching plans, switching AC feasibility/stability checks, and CB reliability and line availability analyses are introduced in Section 2. The proposed methodology is examined through three case studies on the IEEE 118-bus test system in Section 3, followed by some practical discussions provided in Section 4. The paper is eventually concluded in Section 5.

2. Problem description and the proposed framework

This section elaborates the proposed switching implementation framework containing four main modules: the Binary Switching Tree (BST) algorithm, AC feasibility check, stability check, and CB reliability assessment. The framework is illustrated in Fig. 1 and the details come in the following.

2.1. BST algorithm

The proposed BST algorithm is an extended version of the MIP-H algorithm in [23]. The MIP-H finds one switching operation and

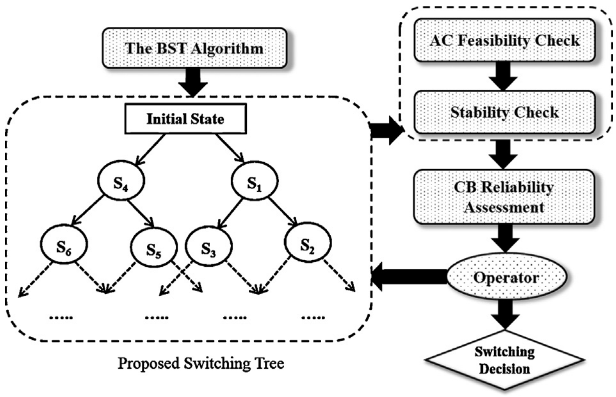

Fig. 1. The overall framework proposed for transmission line switching.

corresponding re-dispatch action per level to iteratively increase the LSR. In contrast, the proposed BST algorithm provides multiple switching actions at each level for further AC feasibility, stability, and CB reliability checks. This paper presents the BST algorithm in terms of the maximum LSR objective but the idea is valid for any other objective function. In this context, the BST algorithm can be triggered by the operator for a forecasted contingency. The switching actions proposed by the BST algorithm are given in a binary tree structure, that is, each path from the root node to a leaf node represents a viable switching sequence and the corresponding intermediate system states. The root node denotes the system state immediately following the contingency. Each non-root node represents an updated system state over its parent node; specifically, the system update from a parent to a child node consists of one line switch and a time-constrained generation re-dispatch. The generation re-dispatch of the child node must be attainable from the parent node's generation re-dispatch by ramping up/down the generators at most in τ minutes (in this paper $\tau = 10$). The BST has two properties: (1) each non-leaf node has two child nodes, the left (right) child is obtained by choosing the one-line switch and generation re-dispatch that combined achieve the largest (second largest) amount of LSR over its parent's state; we refer to this line switch as the line switch *leading to* this left (right) child; (2) given any non-root node, the line switch leading to this node is different from every line switch leading to any sibling of this node's ancestors; this guarantees the diversity of the switching options.

First, an overview of the BST algorithm is presented here. Without loss of generality, we henceforth assume that all the lines are initially closed; however, the BST algorithm can be easily adapted to a more general setting. The BST is built in a breadth-first-search (BFS) order, creating each level from left to right. At each node, say node v, if the stopping criteria have not been met, the BST algorithm will create node v's two child nodes. The left child is created by solving an optimization model to find a line switch and generator re-dispatch that combined recover the most potential load shed. The inputs for this optimization model are: (1) the generation re-dispatch of node v; (2) the line status sets $\hat{K}$ and $\bar{K}$ at node v (the sets of closed and open lines, respectively); and (3) the *Not-to-Switch* (NTS) list which includes all line switches leading to the sibling nodes of node v's ancestors. The right child is created by solving the same model, except that the NTS list also includes the line switch leading to its (left) sibling node. In practice, the operator may not want to switch some specific lines. The proposed BST algorithm can include those transmission lines in the aforementioned NTS list to assure that they will not be switched nor included in the outcome switching tree.

Next, the BST algorithm is described in detail. The BST algorithm takes the following inputs: all DCOPF inputs, the contingency set $\dot{G} \cup \dot{K}$, the potential amount of load shed[1] that may be shed following a contingency, denoted by $LS_{\dot{G}\cup\dot{K}}$, the time interval between two consecutive line switches, τ, the minimum desired improvement in LSR percentage between a child node and its parent, δ (say 0.01%), and the maximum number of levels in the BST, H. The BST algorithm comprises three procedures: (1) $LS_{\dot{G}\cup\dot{K}}$ calculation (as described in [23]); (2) initialization procedure to create the root node and place it in the BFS queue; and (3) the main procedure at every node after it is taken out of the BFS queue.

- *Initialization procedure*

  First, create the root node by setting its BST level as 0 and its current generator levels, denoted by P_g^{Root}, as the generator dispatch in effect at the time that the contingency set $\dot{G} \cup \dot{K}$ occurs. Then, initialize $\bar{K}$ to include all the lines that are currently open and available to be closed, and initialize $\hat{K}$ to include all other transmission lines. Then, set NTS list as empty. Last, push the root node into the BFS queue.
- *Main procedure*

  Step 1: *Check the BFS Queue*: If the BFS queue is empty, then stop and output the BST. Otherwise, pick the first node in the BFS queue, say node v, and continue to ***Step 2***.

  Step 2: *Determine if Node v is a Leaf Node*: Node v is a leaf node (meaning it is the end of a switching sequence) if any of the following criteria is met: there is no load shed at node v, i.e., $LS_{\dot{G}\cup\dot{K}}$ is fully recovered; node v's tree level is equal to H; node v's LSR percentage improvement over its parent node is less than δ; If node v is a leaf node, go back to ***Step 1***. Otherwise, continue to ***Step 3***.

  Step 3: *Create the Left Child of Node v*: To create the left child of node v, say node v_L, we need to find the τ-minute constrained generation re-dispatch and single line switch starting from node v's system state (specified by node v's generator dispatch, P_g^v, and line status, $\hat{K}$ and $\bar{K}$) that combined recover the most load shed. This is done as follows:

  Step 3(a): *Create the NTS List*: Form the node NTS list, denoted by T, by appending the line switch leading to the sibling node of node v to the NTS list used to create node v.

  Step 3(b): *Solve the Following Optimization Problem.*

$$\text{Maximize}\; LS_{\dot{G}\cup\dot{K}} - \sum_{\forall n \in N} u_n \tag{1}$$

Subject to:

$$\theta^{\min} \le \theta_n - \theta_m \le \theta^{\max} \quad \forall k(m,n) \in K \tag{2.a}$$

$$\sum_{\forall k(n,..)} P_k - \sum_{\forall k(..,n)} P_k + \sum_{\forall g(n)} P_g = d_n - u_n \quad \forall n \in N \tag{2.b}$$

$$P_k^{\min}(1-s_k) \le P_k \le P_k^{\max}(1-s_k) \quad \forall k \in \hat{K} \tag{2.c}$$

$$B_k(\theta_n - \theta_m) - P_k + s_k.M_k \ge 0 \quad \forall k \in \hat{K} \tag{2.d}$$

$$B_k(\theta_n - \theta_m) - P_k - s_k.M_k \le 0 \quad \forall k \in \hat{K} \tag{2.e}$$

$$P_k^{\min}.s_k \le P_k \le P_k^{\max}.s_k \quad \forall k \in \bar{K} \tag{2.f}$$

$$B_k(\theta_n - \theta_m) - P_k + (1-s_k).M_k \ge 0 \quad \forall k \in \bar{K} \tag{2.g}$$

$$B_k(\theta_n - \theta_m) - P_k - (1-s_k).M_k \le 0 \quad \forall k \in \bar{K} \tag{2.h}$$

[1] Instead of using the less tractable load shedding dynamically triggered by relays, the load shed in our paper is defined as the difference between the total demand during normal system state and the amount of demand still fulfilled following the contingency set $\dot{G} \cup \dot{K}$.

$$\max\left\{P_g^{\min}, P_g^v - \tau r_g\right\} \le P_g \le \min\left\{P_g^{\max}, P_g^v + \tau r_g\right\} \quad \forall g \in G\backslash\dot{G} \tag{2.i}$$

$$0 \le u_n \le d_n \quad \forall n \in N \tag{2.j}$$

$$P_k = 0 \quad k \in \dot{K} \tag{2.k}$$

$$P_g = 0 \quad g \in \dot{G} \tag{2.l}$$

$$s_i = 0 \quad \forall i \in T \tag{2.m}$$

$$\sum_{\forall k \in K\backslash\dot{K}} s_k = 1 \tag{2.n}$$

$$s_k \in \left\{0, 1\right\} \quad \forall k \in K\backslash\dot{K} \tag{2.o}$$

The main decision variables in this optimization model are s_k and u_n, where s_k determines the switching action at line k and u_n denotes the unfulfilled demand at node n. The objective (1) is to maximize the LSR associated with the contingency set $\dot{G} \cup \dot{K}$; constraint (2.a) sets the range for the difference between the angles of adjacent buses. The node balance constraints (2.b) are analogous to those in the DCOPF model, but allow for partial demand fulfillment. Constraints (2.c)–(2.e) and (2.f)–(2.h) reflect the set of closed and open lines, respectively; constraints (2.c) and (2.f) set the thermal limits, while constraints (2.d), (2.e), (2.g), and (2.h) determine the line power flow. The reachable re-dispatch limits for the online generators are set by constraints (2.i), where P_g^v denotes the generator dispatch at node v. Constraints (2.j) set the bound for the unmet demand at each node. The line and generator outages are reflected in constraints (2.k) and (2.l), respectively. Constraints (2.m) force not to switch the lines in the NST list. Constraint (2.n) allows only one line switch (which significantly accelerates the computations).

Step 3(c): *Record the System State for Node v_L*: Save the line switch, generation dispatch $P_g^{v_L}$ and update line status sets $\hat{K}$ and $\bar{K}$; then record the LSR.

Step 3(d): *Set the Tree Level*: Set the level of the node v_L as node v's level plus 1.

Step 3(e): *Update the BST Queue*: Append node v_L to the end of BST queue.

Step 4: *Create the Right Child of Node v_L*: This step is identical to ***Step 3*** except that the NTS list to create node v's right child, say node v_R, also contains the line switch leading to node v_L.

Step 5: *Compute and Record the LSR for Time-constrained Re-dispatch-only Option Starting from Node v*: Specifically, we need to find the τ-minute constrained generation re-dispatch starting from node v's system state that recovers the most potential load shed. This is done by solving the optimization model in ***Step 3(b)*** with two modifications: removing constraint (2.n) and setting the values of all switching variables, s_k, to zero (note that by doing so, the model in ***Step 3(b)*** is reduced to a simple LP problem).

Note: The re-dispatch-only LSR at each non-leaf node in the BST is provided for two main purposes: (1) as a benchmark to allow the operator evaluate the effectiveness of the suggested switches leading to that node's child nodes; (2) to give the operator the re-dispatch-only option in case he/she prefers it over the proposed switches or uses it as a fallback option in case of CB failure or other restricting conditions.

Step 6: Go to ***Step 1***.

As mentioned earlier, the BST algorithm can be modified to find switching plans with different objectives. For instance, if one wants to minimize generation cost, three minor changes are needed: (1) replace the objective function to minimize the total generation cost, (2) remove the u_n variables and (3) keep track of total generation cost at each node of the BST.

2.2. AC feasibility and stability check

The output of the proposed BST algorithm is an *H*-level BST and the corresponding optimized generation schedules and loading profile. Since the DCOPF always assumes flat voltage profile of 1 per unit for the generators, it does not consider the reactive power and voltage constraints and as a consequence, the resulting solutions may or may not be AC feasible. AC feasibility, hence, needs to be assessed for each proposed switching option. For AC power flow, the original network data excluding the opened lines with the generation schedules and loading patterns suggested by the BST algorithm are used. If the AC power flow does not converge, different adjustments may be tried to aid the convergence with the available reactive power sources, e.g., shunts, generator voltage set points, transformer tap settings, etc. If AC feasibility is achieved with all the adjustments satisfying the generator reactive power constraints, then the transient stability is performed using the output of the AC load flow as the initial conditions for the machines. If the AC power flow is not feasible even with all the reactive power resources at their maximum limits, then the solutions are concluded infeasible. In practice, utilities commonly do some adjustments to the DC solution for AC feasibility. Even after all the possible adjustments, if the AC solution is not feasible, then the DCOPF solution needs to be rethought.

Transmission line switching is a large disturbance in the system. Transient stability simulations, if simulated for longer time, will help in tracking both the initial impact of switching and the oscillatory behavior after the switching is implemented. It is assumed here that the time between consecutive switching operations is sufficient for damping of the electromechanical oscillations. For the transient stability simulations, the generation schedules and loading patterns corresponding to the previous switching actions are taken as the initial condition for the current switching action. The analysis has to be conducted at each level of the switching tree. This will eventually lead to various sets of AC feasible and stable switching actions which can be safely implemented.

2.3. CB reliability assessment

Switching or de-energizing a transmission line requires isolation of the sources feeding the line, which involve operating several CBs. Mal-operation of any of these CBs is an impediment to the successful execution of switching operation. It is, hence, important to take the CB reliability into account while using the topology control in day to day operations. Inspired by the wide deployment of smart sensors in the system in recent years, CB condition and reliability assessment using condition monitoring data have become popular. In this paper, a dynamic procedure employing the CB control circuit monitoring data is employed to find the CB's failure probability index, which is regarded as its reliability measure. The interested readers are referred to [27] for more detailed information on the algorithms and procedures. There are several other methodologies in the literature that can be employed individually or collectively for assessing the CB reliability [28]. The failure probability index employed in this paper can be dynamically updated as and when new monitoring data arrive, providing a continuous quantitative measure of CB reliability over time.

2.4. Approach for identifying the reliable switching options

A new decision framework is proposed in this paper which offers the operator not only a set of switching actions, as introduced earlier through the BST algorithm, but also the mean benefit index associated with each switching action taking the CB reliability and line availability conditions into account. At each level of the tree, the operator can select the switching option with the highest mean

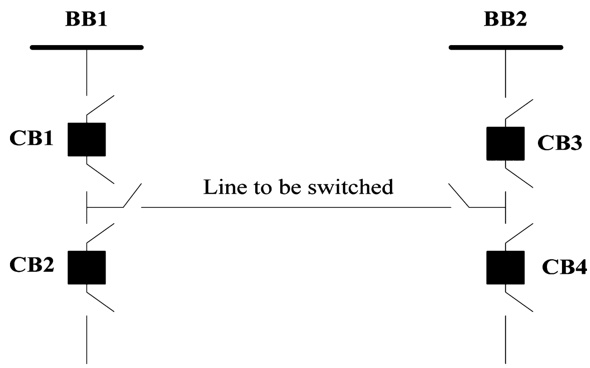

Fig. 2. A sample line for switching obtained by the BST algorithm in a breaker-and-a-half substation configuration.

benefit index. However, the operator can use his/her own experience and other criteria to select the best switching option at every level of the tree. The main step in evaluating the mean benefit index associated with each switching action is to determine the line availability index (probability of switching success) and also the incremental benefits from the successful implementation of each switching action. Here, the availability index of a transmission line for successful switching is calculated according to the substation configuration. This is illustrated using a line switching example having a breaker-and-a-half substation configuration as shown in Fig. 2. There are four CBs involved in switching this line. The current practice in line switching for transmission voltages higher than 138 kV mandates opening the CBs at one end of the line, one at a time, followed by opening the CBs at the other end within a couple of minutes. Open ended lines at such high voltages are prone to the Ferranti effect (rise of voltage on the open end) which may result in insulation damages and unsafe conditions. As a result, in such high voltage levels, if only one side was successfully opened, the operators would reclose it to avoid unsafe conditions. For switching implementation of transmission lines at 138 kV or lower voltage levels, or shorter lines, opening one end of the line may be sufficient. So, Eqs. (4) and (5) are introduced accordingly to evaluate the availability of transmission lines considering the associated CB reliability and health conditions.

$$P^t(S_i) = \prod_{i=1}^{4} \left(1 - \mathrm{FP}^t(B_i)\right) \quad \forall V > 138\,\mathrm{kV} \tag{4}$$

$$P^t(S_i) = \prod_{i=1}^{2} \left(1 - \mathrm{FP}^t(B_i)\right) + \prod_{i=3}^{4} \left(1 - \mathrm{FP}^t(B_i)\right) - \prod_{i=1}^{4} \left(1 - \mathrm{FP}^t(B_i)\right) \quad \forall V \le 138\,\mathrm{kV} \tag{5}$$

where in (4), all the four CBs associated with the line need to be reliable to make the switching action successfully implemented, while in (5), one pair of the CBs at either end of the line needs to be reliable for successful switching implementation. The procedure continues with the evaluation of incremental benefits gained from each switching action. Every line switching option in the switching tree is expected to provide some benefits to the system operator depending on the objective function used in the optimization algorithm. For example, if the minimization of generation cost is the objective, an obtained cost saving can be treated as the benefit. Similarly, if the objective function is the LSR, then the amount of load shed recovered due to each switching option is the benefit gained. If the CB fails to operate, then the line switching cannot be realized and the switching benefits will be lost. However, in such cases of CB

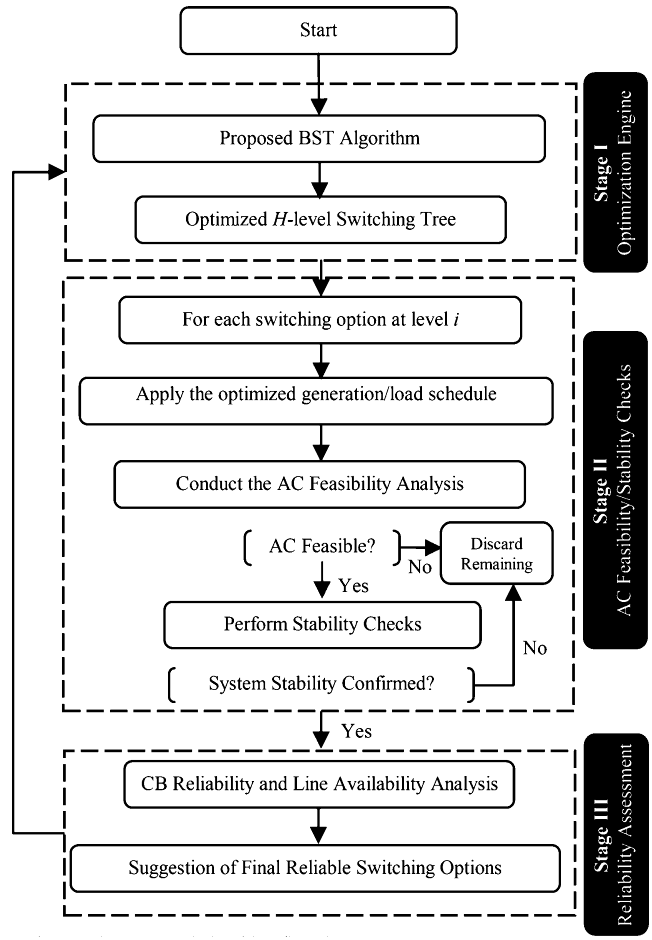

Fig. 3. The proposed algorithm flowchart.

failure, the operators may obtain the benefits by implementing the re-dispatch-only solution. Hence, a mean benefit index is proposed in this paper for each switching action at every level of the switching tree taking into account the following factors: (a) probability of successful switching implementation in terms of the associated CB reliability; (b) the incremental benefits (in this paper, the benefit is in terms of MW load shed recovered) from each single switching action and the corresponding generation re-dispatch compared to the previous state; (c) probability of switching implementation failure due to the unavailability or failure of the associated CBs; (d) the benefits (in this paper, the benefit is in terms of MW load shed recovered) from the generation re-dispatch-only practice (when the switching action cannot be implemented successfully) compared to the previous state. The proposed mean benefit index for each switching action is calculated as:

$$MB^t(S_i) = P^t(S_i).B^t(S_i) + (1 - P^t(S_i)).B^t(\mathrm{RD}_i) \tag{6}$$

The mean benefit index is calculated at each node considering only the incremental benefits from the previous state to the next immediate state. At each level of the tree, each switching option provided to the operator will be accompanied by its mean benefit index. Having one end of the line switched, the remaining end will experience less stress because of the no load switching; the possibility of failure can be, hence, less in this case. So to aid the operator in deciding which end of the line to start with, the availability index is also calculated for both ends of the line separately using (5). The operator can then select to begin switching the end of the line with higher index of reliability. It implies that the reliable CBs are always triggered first to start the switching process. Fig. 3 illustrates the proposed framework's entire process.

Note that if either of the aforementioned checks fails at any level of the tree, the proposed BST algorithm could be called again to start at that level to propose an alternative switching option (to do this, the only change to the BST algorithm, in ***Step 3(b)***, is to add them to the NTS list). However, this decision can be made by the operator looking at the entire tree. If the switching tree does not result in at least one implementable switching path, i.e., at least one path which satisfies the AC feasibility and stability checks with reliable CBs for switching or any other practical concerns apart from these, then the operator may choose to re-run the BST algorithm to get new sets of acceptable results.

3. Case studies: IEEE 118-bus test system

In this section, the proposed framework is applied on the IEEE 118-bus test system, which contains 186 transmission lines and 19 generators with the installed capacity of 5859.2 MW serving a total demand of 4519 MW [29,30]. The one-line diagram of the studied network is illustrated in [31]. The results are presented for contingency planning scenarios where maximizing LSR is regarded as the optimization objective function. Our proposed framework is used to plan for the non-trivial contingencies, i.e., those whose impacts on the system cannot be mitigated by a time-unconstrained generation re-dispatch alone. These non-trivial test cases were run on a desktop machine with 12 GB RAM and two 2.40 GHz Intel Xeon processors. It took at most 18 s to execute the BST algorithm for each case study and about 2–3 s for the AC feasibility, stability, and CB reliability simulations of each switching action.

3.1. Case study 1: topology control application to a single-order generator contingency

One such non-trivial case, the outage of generator 13 (G13), is considered in this paper to demonstrate the effectiveness of the proposed framework. The initial load shed caused by the G13 contingency is 805.2 MW, of which only 584.3 MW (72.6% of the system total load shed) can be recovered through the time-unconstrained re-dispatch. Reconfiguration is needed in this scenario to recover the load shed. Fig. 4 illustrates the switching actions obtained from the BST algorithm.

In this figure, each node/box denotes a system state (the LSR on each node is given both in percentage and MW). The numbers on top of each solid-line arrow represent the line switches leading to the node in the lower level. The number in the boxes located in the upper left-hand side of each node/box represents the node index. The LSR obtained by the re-dispatch only solution is presented in the hexagons below each parent node (each hexagon and corresponding parent node are connected by a dashed arrow). The figure illustrates that the operator is offered two switching options (more switching options can be provided at each level if desired) at each node: the switching leading to its left child and the switching leading to its right child. For example at level 1, line 51 and line 115 can be switched (note that with either switch, the LSR (77.8% or 76.1%) is already greater than that obtained by doing only a 40-min re-dispatch – 72.6%). If the operator decides to select line 51 at level 1, he/she has two line switching options, i.e., lines 112 and 116, to implement at level 2.

The optimized generation and load schedules for each switching option would be the other outputs of the BST algorithm. These changes at each level of the tree are used in an AC power flow solver. AC power flow problems were solved using the Matpower version 4.1 toolbox in MATLAB [32]. The AC infeasible switching solutions, line 64 at level 3 and lines 110 and 114 at level 4, are shown in gray boxes in Fig. 4. Transient stability simulations are conducted using the 6th order models for synchronous machines for 20 s. First swing, multi swing, and small oscillation instabilities can be detected in such time domain simulations. The solutions which are first swing unstable, line 132 at level 3, are highlighted in black boxes. These cases are indeed unstable after the second swing. If the operator chooses to switch the line 141 at level 2, then he/she is left with only one switching option, i.e., line 112, since switching line 132 is an unstable case. The operator may choose to re-run the optimization starting from level 2 as the base case and get another alternate switching option excluding the two already considered. This would be faster than running the entire optimization starting from the beginning. CB reliability assessment is then performed at each level. The results of the proposed benefit assessment framework for decision making at each level are tabulated in Table 1 assuming the associated substation configurations to be breaker-and-a-half scheme and the transmission voltages are higher than 138 kV [29]. The CB failure probabilities are simulated based on a set of real condition monitoring data introduced in [27] and the employed values for the proposed switching candidates are demonstrated in Table 2. The switching level 1 offers two options to maximize LSR in response to the G13 outage. Though both solutions meet AC feasibility and stability requirements, the benefit analysis shows that switching line 115 is of higher mean benefit at this level and is highlighted with a thick arrow. Similarly, at each non-leaf node of the tree in Fig. 4, the switching action with the highest mean benefit is highlighted with thick arrows. Note that the conditions of all the responsible CBs associated with a transmission line have been taken into account for calculating the mean benefit indices. An example calculation assuming the selection of highest mean benefit index switching option at each level by the operator is shown in Table 1 (however, recall that the operator may choose to deviate from this sequence due to other considerations; e.g., he/she may choose to switch lines 51, 112 and 111 since this would achieve 100% LSR with the least number of switches).

Once the operator selects a line for switching based on the mean benefit index or from his/her own experience, the operator's concern then might be to select the most reliable switching process. Here, solely the CBs related to the corresponding end-of-line need to be considered. The results for the highlighted sequence in Table 1 are tabulated in Table 3. The proposed approach is generic enough to be applied to various substation configurations. From Table 3 for line 115 at level 1, we conclude that it is more reliable to start with the from-end of the line since it has higher mean benefit index, i.e., 612.035, compared to the other end with the value of 609.880. The benefit analyses in Tables 1 and 3 show that line 141 may be selected at level 2 and, if so, the switching process has to start with the to-end of the line. Similarly, lines 112 and 106 can be selected at switching levels 3 and 4, respectively. Switching these two lines would be started through the to-end of the lines since they are more reliable to start the process. These options 115, 141, 112, 106 are marked in bold. Note that our method provides several AC feasible, stable, and reliable switching options. The load shed can be fully/partially recovered via a combination of switching action and re-dispatch through the proposed framework. Due to the variety of involved CBs with different reliability indicators, the final sequence may or may not lead to 100% LSR, which is not uncommon in practice.

Here, we demonstrate that the benefit (the LSR) obtained by the BST algorithm is due to both the switching actions and the re-dispatch. Specifically, at every node, if one were to perform only an optimal re-dispatch (with no switching), the LSR would be much less. This is seen in Fig. 4 by comparing, at each non-leaf node, the LSR percentages at both of its child nodes and the re-dispatch only LSR percentage (inside the hexagon). Remarks: (1) All LSR percentages obtained with line switching are substantially higher

Table 1
Benefit assessment of the switching tree concerning the CB reliability condition: case study 1.

Switching line			$P^t(S_i)$ (%)	$B^t(S_i)$ (MW)	$MB^t(S_i)$
No.	From	To			
			Switching level 1 ($B^t(\mathrm{RD}_1)$ = 533.847 MW)		
51	30	38	0.727219	612.7	591.191
115	68	69	0.693979	626.4	**598.077**
			Switching level 2 ($B^t(\mathrm{RD}_2)$ = 28.182 MW)		
141	81	80	0.678778	137.5	**102.385**
116	68	81	0.614512	137.5	95.359
			Switching level 3 ($B^t(\mathrm{RD}_3)$ = 4.026 MW)		
112	65	66	0.580683	33.8	**21.3153**
132	77	80	0.655972	16.9	12.4709
			Switching level 4 ($B^t(\mathrm{RD}_4)$ = 0 MW)		
114	66	67	0.618354	7.5	4.63765
106	62	66	0.698266	7.5	**5.23699**

Table 2
CB failure probability values for the proposed switching candidates: case study 1.

Switching line	CB failure probability index				Switching line	CB failure probability index			
	From-end CBs		To-end CBs			From-end CBs		To-end CBs	
51	0.0523	0.0891	0.0478	0.1153	**112**	0.2499	0.0346	0.1689	0.0355
115	0.0894	0.0723	0.0863	0.1009	**132**	0.1239	0.0246	0.1276	0.1201
116	0.1127	0.0756	0.1705	0.0968	**114**	0.1468	0.0673	0.0723	0.1624
141	0.1788	0.0764	0.0699	0.0378	**106**	0.1381	0.1129	0.0408	0.0479

than those with re-dispatch only. (2) In only 8 out of 28 nodes, the re-dispatch-only solution achieves 99% or more of the LSR percentage recovered by switching; moreover, at those 8 nodes, the corresponding re-dispatch only results already benefitted from the previous switching actions that led to their parents. (3) The LSR percentages for 10-, 20-, 30-, and 40-min re-dispatch-only solutions are 66.3%, 71.3%, 72.6%, and 72.6%, respectively; in contrast, the LSR percentages recovered by the BST algorithm after 10, 20, 30 and 40 min (i.e., at levels 1, 2, 3 and 4, resp.) are, on average, 77.0%, 91.1%, 95.5%, and 96.5%, respectively; furthermore, the maximum LSR percentage without any switching is only 72.6%. We conclude that switching is very beneficial to maximize the LSR.

3.2. Case study 2: topology control application to a second-order line-generator contingency

Another non-trivial case, the second order contingency involving the outage of generator 17 (G17) and transmission line 119 (L119) is studied to demonstrate the capability of the suggested framework in handling higher-order contingencies. The initial load shed caused by the G17-L119 contingency is 352 MW, of which only 277.38 MW (78.8% of the system total load shed) can be recovered through the time-unconstrained re-dispatch. Fig. 5 illustrates the switching actions obtained from the BST algorithm with the objective of maximizing LSR. The AC feasibility, stability, and CB

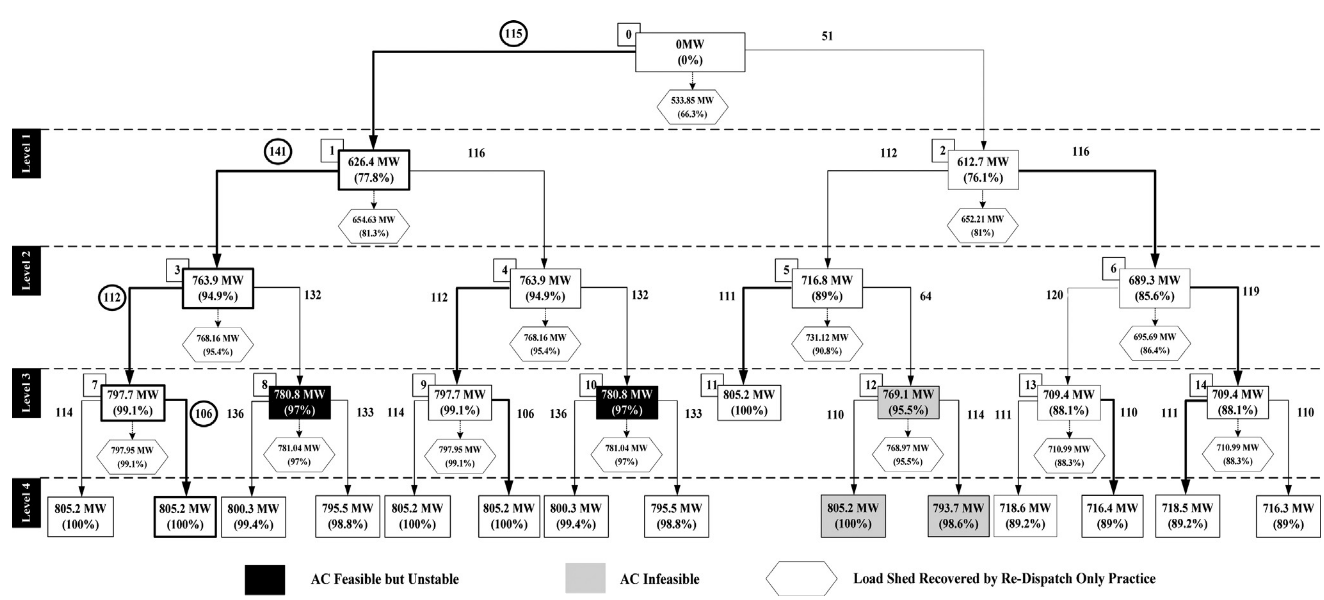

Fig. 4. The proposed switching tree as the BST algorithm output for the case study 1: G13 single-order contingency.

Table 3
Benefit assessment to determine which end-of-line is used to start the switching process: case study 1.

Selected line			$P^t(S_i)$ (%)	$B^t(S_i)$ (MW)	$MB^t(S_i)$
No	From	To			
	68	69	**Switching level 1** ($B^t(\mathrm{RD}_1) = 533.847$ MW)		
115	From-end		0.8448	626.4	**612.035**
	To-end		0.8215	626.4	609.880
	81	80	**Switching level 2** ($B^t(\mathrm{RD}_2) = 28.182$ MW)		
141	From-end		0.7585	137.5	111.095
	To-end		0.8949	137.5	**126.015**
	65	66	**Switching level 3** ($B^t(\mathrm{RD}_3) = 4.026$ MW)		
112	From-end		0.7241	33.8	25.586
	To-end		0.8019	33.8	**27.903**
	62	66	**Switching level 4** ($B^t(\mathrm{RD}_4) = 0$ MW)		
106	From-end		0.7646	7.5	5.734
	To-end		0.9132	7.5	**6.849**

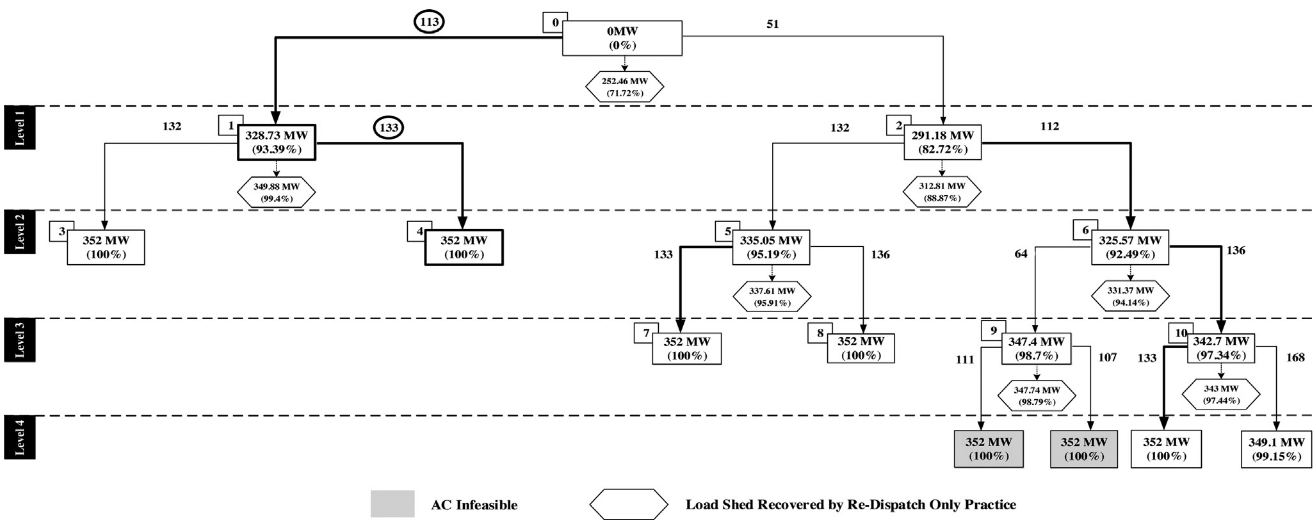

Fig. 5. The proposed switching tree (BST algorithm output) for the case study 2: G17-L119 contingency.

reliability checks are conducted on the obtained solutions and Fig. 5 shows the associated results. In the suggested switching tree for this contingency, there are several switching sequences that recover 100% of the total load shed. This provides the operator with plenty of flexibility in decision making for practical implementations. Also, there are two AC infeasible switching actions recognized: transmission lines 111 and 107 both located at level 4 of the tree and highlighted in gray. Transient stability checks

Table 4
Benefit assessment of the switching tree concerning the CB reliability condition: case study 2.

Switching line			$P^t(S_i)$ (%)	$B^t(S_i)$ (MW)	$MB^t(S_i)$
No.	From	To			
			Switching level 1 ($B^t(\mathrm{RD}_1) = 252.46$ MW)		
51	30	38	0.7235	291.18	280.475
113	65	68	0.6504	328.73	**302.072**
			Switching level 2 ($B^t(\mathrm{RD}_2) = 21.15$ MW)		
132	77	80	0.6155	23.27	22.457
133	77	80	0.8085	23.27	**22.865**

Table 5
Benefit assessment to determine which end-of-line is used to start the switching process: case study 2.

Selected line			$P^t(S_i)$ (%)	$B^t(S_i)$ (MW)	$MB^t(S_i)$
No	From	To			
	65	68	**Switching level 1** ($B^t(\mathrm{RD}_1) = 252.46$ MW)		
113	From-end		0.8390	328.73	**316.450**
	To-end		0.7753	328.73	311.593
	77	80	**Switching level 2** ($B^t(\mathrm{RD}_2) = 21.15$ MW)		
133	From-end		0.8809	23.27	23.018
	To-end		0.9178	23.27	**23.096**

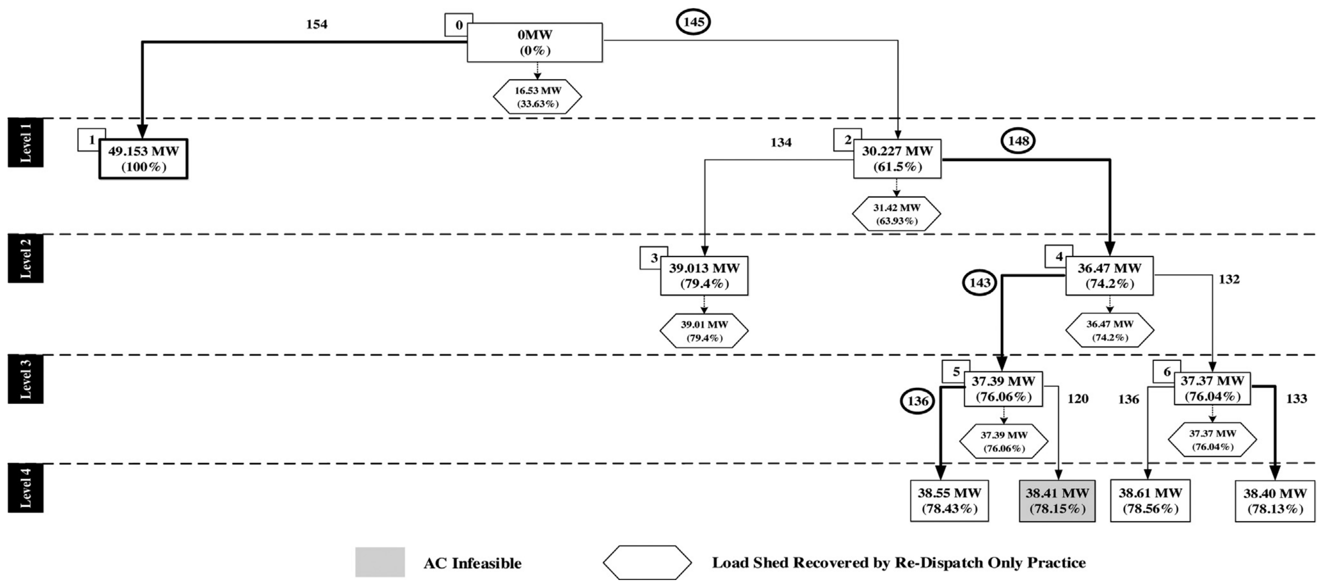

Fig. 6. The proposed switching tree as the BST algorithm output for the case study 3: L11-L152 contingency.

passed in all the switching solutions except on the AC infeasible ones. Similar to the previous case study, the operator is offered two switching options at each node: at level 1, line 113 and line 51 can be switched. If the operator decides to select either one, he/she would have two other line switching options at level 2, and so on. The results of the proposed benefit assessment framework for decision making at each level are tabulated in Table 4 assuming the associated substation configurations to be breaker-and-a-half scheme and the transmission voltages are higher than 138 kV. The switching action with the highest mean benefit at each non-leaf node of the tree is highlighted with thick arrows in Fig. 5. The benefit analysis shows that at Level 1, switching line 113 would bring higher mean benefits compared to switching line 51. An example mean benefit index calculation (assuming that the operator always selects the switching option with the highest mean benefit index) is shown in Table 4 and the selected switching actions are also highlighted with thick arrows and circles in Fig. 5. However, recall again that the operator may choose to deviate from this sequence due to other considerations. The selected switching sequence is able to recover 100% of the total load shed. Table 5 also demonstrates the CB reliability analysis which helps the operator to decide which end-of-line to switch first. From Table 5, it can be concluded that the selected switching sequence would better be implemented starting at the from-end and to-end of lines 113 and 133, respectively.

3.3. *Case study 3: topology control application to second-order line-line contingency*

The second order contingency involving the outage of transmission lines 11 (L11) and 152 (L152) is selected as the third case study. The initial load shed caused by the L11-L152 contingency is 49.15 MW, of which only 18.09 MW (36.8% of the system total load shed) can be recovered through the time-unconstrained re-dispatch. Fig. 6 illustrates the switching actions obtained from the BST algorithm. In the proposed switching tree for this contingency, there is one AC infeasible and unstable switching action, (line 120 at level 4) which is shown in gray. Transient stability checks passed in all the other switching solutions. The results of the proposed benefit assessment framework for decision making at each level are tabulated in Table 6. The mean benefit assessment suggests the operator to select line 154 at level 1, through which the total load shed would be completely recovered with this single switching action; however, if for any reasons, line 145 is selected for switching at level 1, he/she would have two line switching options, i.e., lines 134 and 148, to implement at level 2, and so on. In such cases, an example calculation of a switching sequence decision by the operator is shown in Table 6. The selected switching sequence is able to recover 78.43% of the total load shed. Table 7 demonstrates the CB reliability analysis which helps the operator to decide which

Table 6
Benefit assessment of the switching tree concerning the CB reliability condition: case study 3.

Switching line			$P^t(S_i)$ (%)	$B^t(S_i)$ (MW)	$MB^t(S_i)$
No.	From	To			
			Switching level 1 ($B^t(\mathrm{RD}_1)$ = 16.53 MW)		
154	89	92	0.6505	49.153	**37.75**
145	83	85	0.7235	30.227	26.440
			Switching level 2 ($B^t(\mathrm{RD}_2)$ = 1.194 MW)		
134	77	82	0.5667	8.786	5.496
148	85	88	0.9401	6.243	**5.941**
			Switching level 3 ($B^t(\mathrm{RD}_3)$ = 0 MW)		
143	82	96	0.6521	0.92	**0.600**
132	77	80	0.5750	0.90	0.518
			Switching level 4 ($B^t(\mathrm{RD}_4)$ = 0 MW)		
136	79	80	0.6850	1.16	**0.795**
120	69	77	0.6155	1.02	0.628

Table 7
Benefit assessment to determine which end-of-line is used to start the switching process: case study 3.

Selected line			$P^t(S_i)$ (%)	$B^t(S_i)$ (MW)	$MB^t(S_i)$
No	From	To			
	83	85	**Switching level 1** ($B^t(\mathrm{RD}_1) = 16.53$ MW)		
145	From-end		0.8571	30.227	**28.270**
	To-end		0.8441	30.227	25.515
	85	88	**Switching level 2** ($B^t(\mathrm{RD}_2) = 1.194$ MW)		
148	From-end		0.9713	6.243	**6.082**
	To-end		0.9019	6.243	5.748
	82	96	**Switching level 3** ($B^t(\mathrm{RD}_3) = 0$ MW)		
143	From-end		0.8516	0.92	**0.783**
	To-end		0.7657	0.92	0.705
	79	80	**Switching level 4** ($B^t(\mathrm{RD}_4) = 0$ MW)		
136	From-end		0. 7464	1.16	0.866
	To-end		0. 9178	1.16	**1.065**

end-of-line to switch first. It can be concluded that the selected switching sequence should be implemented starting at the from-end, from-end, from-end and to-end of the lines 145, 148, 143, and 136, respectively.

4. Discussions

- In this paper, we used the bus-branch model for the switching optimization framework (creating the BST tree), the AC feasibility check and stability analysis. We used the node-breaker configurations to calculate the mean benefit index based on the CB reliability indicators and to determine the most reliable end-of-line to implement each switching action. In practice, there is a model-conversion requirement from the bus-branch model into the node-breaker configuration models. Future research is needed to efficiently incorporate the node-breaker models into switching optimization formulations.
- Regarding the N-k contingency stability checks after switching implementations, recent literature suggests that the system should still be able to meet the N-1 criterion after switching implementation [9,22,33]. Our proposed BST framework is general enough to be integrated with such algorithms and hence will allow flexible decision making using a switching options tree.
- The operation of CBs for frequent switching implementations is not free. System CBs might need maintenance after several operations which may impose some additional costs. Since the true marginal cost of switching a CB is difficult to quantify at this time, we assumed a zero marginal cost to switch a CB. The reasoning is that the cost of switching a CB is negligible compared to the gained monetary benefits by minimizing the customer outage duration in the cases of contingency mitigation through implementation of the proposed switching actions. If the suggested solution framework is going to be used in day-to-day operations, the impact of CB maintenance and degradation due to an increase in the switching frequency need to be investigated and considered in the cost functions.
- Since the suggested framework is intended as a corrective tool in the day to day operational planning scenarios, usually the computational time requirement for the whole framework including the stability/AC feasibility and CB reliability considerations is less than an hour. In reference [23], the computational efficiency of the MIP-H algorithm has been evaluated on a real-life, large-scale test case consisting of 13k buses, 1k generators, and 19k transmission lines. Since the BST algorithm is an extended version of MIP-H, it is reasonable to conclude that its results will be reached just as efficiently and quickly as those obtained with the MIP-H. Specifically, in [23], the MIP-H algorithm was expected to reach a speed of one-minute computational time per contingency for the above real-life large-scale network within a few years considering the rapid advances in both computing hardware and computational capability of modern optimization solvers. This expected improvement in solving speed can also further be expedited by using a parallelized version of the current program.
- The BST algorithm proposed in this paper uses MIP to determine the best lines to switch jointly with the associated best generator re-dispatch (i.e., the suggested algorithm co-optimizes the generation along with the network topology). We note that there are sensitivity-based approaches that are also able to determine appropriate switching actions. The proposed framework is modular and, thus, can use sensitivity-based approaches instead of MIP to determine the switching actions; this change will speed up the algorithm at the cost of losing the benefits expected from the co-optimization process.

5. Conclusion

The following remarks are the paper contributions:

- A new practical decision making paradigm for transmission switching to empower the operator, in an advisory mode, with a diverse set of switching actions along with their benefits is proposed.
- The proposed framework for implementation of topology control ensures the AC feasibility, stability, and acceptable circuit breaker (CB) reliability.
- Using efficient DCOPF based optimization, multiple switching options are determined per contingency and presented to the operator as a binary decision tree.
- The AC feasibility and stability checks are conducted at each level of the tree to ensure the reliable implementation of the proposed options in practice.
- A CB reliability assessment method using real-time CB condition monitoring signals to assess the availability of CBs for switching implementation is proposed to be included in the framework.
- The presented framework can be integrated as a corrective tool in day to day operation planning scenarios in response to system critical contingencies.

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