Optimal Transmission Switching With Contingency Analysis

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***Abstract*—In this paper, we analyze the N-1 reliable dc optimal dispatch with transmission switching. The model is a mixed integer program (MIP) with binary variables representing the state of the transmission element (line or transformer) and the model can be used for planning and/or operations. We then attempt to find solutions to this problem using the IEEE 118-bus and the RTS 96 system test cases. The IEEE 118-bus test case is analyzed at varying load levels. Using simple heuristics, we demonstrate that these networks can be operated to satisfy N-1 standards while cutting costs by incorporating transmission switching into the dispatch. In some cases, the percent savings from transmission switching was higher with an N-1 DCOPF formulation than with a DCOPF formulation.**

***Index Terms*—Integer programming, power generation dispatch, power system economics, power system reliability, power transmission control, power transmission economics, transmission planning.**

NOMENCLATURE

Indices

n, m	Nodes.
k	Transmission element (line or transformer).
g	Generator.
d	Load.
c	Operating state; $c = 0$ indicates the no contingency state (steady-state); $c > 0$ is a single contingency state.

Variables

θ_{nc}	Voltage angle at node n for state c.
P_{nmkc}	Real power flow from node m to n for transmission element k for state c.
P_{ngc}	Real power supply from generator g at node n for state c.
z_k	Binary variable for transmission element k (0 open, 1 closed).
z_g	Binary variable for generator g (0 down, 1 operational).

Parameters

ρ_c	Probability of state c. $\sum_c \rho_c = 1$.
$\theta_c^{\max}, \theta_c^{\min}$	Max and min voltage angle in state c.
$P_{gc}^{\max}, P_{gc}^{\min}$	Max and min capacity of generator g in state c.
$P_{kc}^{\min}, P_{kc}^{\max}$	Max and min rating of transmission element k in state c.
P_{nd}	Real power load at node n.
c_{ngc}	Cost of production from generator g in state c.
C_{nk}	Capital or startup costs of asset k.
B_k	Electrical susceptance of transmission element k.
$N1_{ec}$	Binary parameter that is 0 when the element e is the contingency and $c > 0$, 1 otherwise.
T	Set of transmission elements.
G	Set of generators.

Heuristic Parameters

TC_J	Total system cost with J opened transmission elements.
J	Number of open transmission elements.
H	Maximum number of transmission elements allowed to be switched.
K	Set of transmission elements allowed to be switched.

I. INTRODUCTION

TRANSMISSION elements (lines or transformers) are traditionally treated as assets that are fixed within the network, except during times of forced outages or maintenance. This traditional view does not describe them as assets that operators have the ability to control. However, it is acknowledged, both formally and informally, that system operators can, and do, change transmission elements' state thereby changing the topology of the network.

In operations, there is usually not a single optimal topology for all periods in the time horizon and/or for all possible market realizations. Operators switch transmission elements to improve voltage profiles or increase transfer capacity [1]. For example, it is an accepted practice to open light-loaded transmission lines at night for better voltages profiles [2]. These decisions are made

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under a set of prescribed rules by the operator, rather than included in the optimization problem.

Transmission switching provides flexibility to the grid and may be used as a control method for problems including voltage stability, line overloading [3], [4], loss or cost reduction [5], [6], system security [7], or a combination of these [8]–[10]. Numerous special protection systems (SPS) address specific instances of switching during emergency conditions. Some SPSs open lines during emergency conditions, demonstrating that it can be beneficial to change the topology during emergency conditions.

The concept of optimal transmission dispatch was introduced by O'Neill *et al.* [12] in a market context, in which the dynamic operation and compensation of transmission elements are examined. Fisher [13] provided the mixed integer programming (MIP) direct current optimal power flow (DCOPF) formulation for transmission switching, applied it to the IEEE 118-bus test case, and discussed the effects on varying load profiles and the practical implications of transmission switching. Hedman [14] applied transmission switching to the IEEE 118-bus test case as well and discussed the financial impacts that transmission switching can have on market participants, the added uncertainty as a result of transmission switching, and the policy implications of transmission switching with regards to revenue adequacy of financial transmission rights (FTRs).

Revenue adequacy is maintained for the static dc network [15]. Revenue adequacy is not guaranteed for FTRs if the network topology changes [16]. A simple, theoretical example can be created where there is revenue inadequacy even for transmission switching solutions that increase the total social surplus. Such an example will be published in the future as we are currently working on the issues related to revenue adequacy and transmission switching. Even if there is revenue inadequacy, since the total surplus is guaranteed not to decrease with transmission switching, there is the possibility for Pareto improvements for all market participants.

The optimal transmission switching model is solved by MIP. The use of MIP within the electric industry is growing. Recently, PJM switched from a Lagrangian relaxation (LR) approach to MIP for their generation unit commitment software [17] and for their real-time market look-ahead [1]. These changes are estimated to save PJM over 150 million dollars per year [1], [17]. Furthermore, most US ISOs are testing and planning to switch to MIP in the near future [18].

This paper investigates how transmission switching can increase economic efficiency while maintaining an N-1 secure network. We apply the model to the IEEE 118-bus test case and the IEEE 73-bus test case, also known as the RTS 96 system [19], [20].[1]

The paper is organized as follows. Section II presents the N-1 DCOPF transmission switching formulation for planning and operations. Section III presents a modified version of the general model in Section II, which is used for the computational testing; Section III also discusses the heuristic techniques used for the computational testing. Section IV provides a network overview of the IEEE 118-bus test case along with results. Section V presents a network overview and the results and analysis for the RTS 96 system. Section VI provides a discussion on possible future work and Section VII concludes this paper.

[1]A longer version of this paper is available online; see [21].

II. Model Formulation for Planning and Operations

Although the overall goal is optimality, in a practical setting, proving optimality is less important than improving the solution. The objective is to find the best solution within the available timeframe. For this reason, we do not focus on proving optimality; rather, we focus on finding the best solution within a reasonable timeframe with bounds on possible improvements.

The model presented in Section II-A can be used for both planning and operations. Applying transmission switching in both the planning and operations process can reduce costs. The planning mode includes both switching and construction of new assets since the introduction of assets or new load can change the optimal topology. In planning mode, the model includes construction costs, C_k, a set of proposed new assets, K', a single (usually a peak) period, and the solution time window is at least over night with possibility of parallel computation.[2]

No matter what switching and investments come out of the planning process, the operational reality is almost always different. As real-time approaches some uncertainties are resolved, the decision space constricts, e.g., some generators are no longer available, and the granularity of the model increases. In operations mode there is no investment, but start up costs, C_k, can be included, there may be multiple look-ahead time periods (we do not analyze this problem here), and a more limited solution time window, usually two to three hours for the day-ahead market, for example.

Since an unavoidable element of reliability analysis is uncertainty, we also add to the objective function the probability of an element failure. This creates a two-stage model of uncertainty that minimizes expected costs (see [23] and [24]). The probability of a generator failure is generally of the order of 10^{-2} and a transmission failure is of the order of 10^{-3} or 10^{-4}. If we allow for a failure, for example, a cumulative reserve shortage of 24 hours in ten years with probability, ρ_f, then $\rho_f + \sum_c \rho_c = 1$. All other contingencies besides the N-1 contingencies could cause a failure but their cumulative impact would not exceed this one day in ten-year outage criteria. This model is both a two-stage and a chance-constrained model (see [23] and [24]).

The network is built so that it is able to handle various contingencies, load levels, generator levels, etc. Such situations do not all exist at the same time. A line that is required to be in service to meet N-1 standards for one particular network condition may not be required to be in service during other network conditions. As a result, transmission switching can be feasible even while satisfying the N-1 standards. After a contingency occurs, the system must be reconfigured to survive another contingency in 30 min. This reconfigured topology is not considered within planning, which is another reason why transmission switching should be considered. Likewise, transmission lines are built if they provide a net benefit to the network over the line's lifecycle or they are required in order to meet reliability standards. This is a very granular approach with a high level of uncertainty. There is also no guarantee that the line is beneficial, or required for reliability reasons, during every possible network condition.

[2]PJM uses networked work stations over night to perform reliability computations [22].

Therefore, for the reasons cited above, transmission switching can be beneficial in both transmission planning and operations.

A. *MIP Transmission Switching N-1 DCOPF Model*

The N-1 DCOPF formulation ensures that the system will survive the loss of any single element in the system: a transmission element or generator. The objective is to minimize expected cost [3] subject to physical constraints of the system and Kirchhoff's laws governing power flow. These constraints must be satisfied for all states. Note that, when the demand is perfectly inelastic, minimizing the total cost is the same as maximizing the total social welfare.

This is a lossless model, which allows us to use only one variable to represent a transmission element's power flow. Therefore, the node balance constraints (3) account for flows to bus n (injections) and flows from bus m (withdrawals). If transmission switching were applied to an ac lossy model, losses may increase or decrease due to transmission switching. It may be the case that losses increase thereby requiring more generation. However, it is possible to have a decrease in total cost with an increase in losses since transmission switching allows for previously infeasible dispatches. It is also possible to have the losses decrease (see [6]), which is yet another possible benefit of transmission switching. Injections into a bus are positive (generator supply, power flow to bus n) and withdrawals are negative (load, power flow from bus n). The optimization problem is defined as (1)–(9) at the bottom of the page.

Each decision variable, as defined in the nomenclature, has a new variable for each state c, except for z_k and z_g. State $c = 0$ represents the no-contingency, steady-state variables and constraints whereas all other states represent single generator or transmission contingencies. The formulation above does not include specific restrictions on the generator dispatch and power flow variables for contingencies but it can be modified according to the desired testing. We discuss our assumptions on how the general formulation changes and how we restrict these variables during certain contingencies in Section III, which presents the modifications for our computational tests.

[3]Cost can be interpreted as "bid cost" in a market setting or it can be interpreted as the true cost in a vertically integrated setting.

We introduce a binary parameter for state c and element e, $N1_{ec}$. $N1_{kc} = 0$ represents the loss of transmission element k; $N1_{gc} = 0$ represents the loss of generator g. For $c = 0$, $N1_{e0} = 1$ for all e as this state reflects steady-state operations. There are N (transmission element or generator) contingencies. For $c > 0$

$$N1_{ec} = \left\{ \begin{matrix} 0, & \text{if} c = e \\ 1, & \text{otherwise} \end{matrix} \right\}, \quad \forall c > 0, e \tag{10}$$

$$\sum_{\forall e} N1_{ec} = N - 1, \quad \forall c > 0 \tag{11}$$

$$\sum_{\forall c > 0} N1_{ec} = N - 1, \quad \forall e. \tag{12}$$

The binary parameter forces the transmission element's flow to be zero if it is the contingency within (4); likewise, (7) forces a generator's supply to be zero if it is the contingency.

Equations (5a) and (5b) ensure that if a transmission element is opened, these constraints are satisfied no matter what the values are for the corresponding bus angles. The transmission element is considered opened if it is the contingency, i.e., $N1_{kc} = 0$, or it is chosen to be opened as a result of transmission switching, i.e., $z_k = 0$.

In (5a) and (5b), M_{kc} is often called the "big M" value. When $z_k = 1$ and $N1_{kc} = 1$, the value of M_{kc} does not matter. When either $z_k = 0$ or $N1_{kc} = 0$, the value of M_{kc} ensures that (5a) and (5b) are satisfied regardless of the difference in the bus angles. P_{nmkc} is zero when $z_k = 0$ or $N1_{kc} = 0$ so M_{kc} must be a large number greater than or equal to $\left|B_k\left(\theta_c^{\max} - \theta_c^{\min}\right)\right|$. Without this adjustment to the power flow equations, the buses

$$\text{Minimize}: \quad \text{ETC} = \sum_{g,c} \rho_c c_{ngc} P_{ngc} + \sum_{k \in K'} C_k z_k \tag{1}$$

s.t.: Phase angle constraints for each state

$$\theta_c^{\min} \le \theta_{nc} \le \theta_c^{\max}, \quad \forall\, n, c \tag{2}$$

Node balance constraints for each state

$$\sum_{\forall k | i = n} P_{ijkc} - \sum_{\forall k | j = n} P_{ijkc} + \sum_{\forall g | s = n} P_{sgc} - P_{nd} = 0, \quad \forall\, n, c \tag{3}$$

Transmission constraints for each state

$$P_{kc}^{\min} z_k N1_{kc} \le P_{nmkc} \le P_{kc}^{\max} z_k N1_{kc}, \quad \forall\, k, c \tag{4}$$

$$B_k(\theta_{nc} - \theta_{mc}) - P_{nmkc} + (2 - z_k - N1_{kc}) M_{kc} \ge 0, \quad \forall\, k, c \tag{5a}$$

$$B_k(\theta_{nc} - \theta_{mc}) - P_{nmkc} - (2 - z_k - N1_{kc}) M_{kc} \le 0, \quad \forall\, k, c \tag{5b}$$

$$z_k \in \{0, 1\}, \quad \forall\, k \in K \tag{6}$$

Generation constraints for each state

$$P_{gc}^{\min} N1_{gc} z_g \le P_{ngc} \le P_{gc}^{\max} N1_{gc} z_g, \quad \forall\, g, c \tag{7}$$

$$z_g \in \{0, 1\}, \quad \forall\, g \in G \tag{8}$$

$$K' \subset K \cup G \tag{9}$$

that were connected to this opened transmission element would be forced to have the same bus angle. With this adjustment, the solution corresponds to the case when the transmission element is not present in the network, as desired.

All solutions from the N-1 DCOPF transmission switching problem must satisfy the N-1 standards. The model does not prevent a generator from being isolated from the network. If there exists a feasible solution with an isolated generator, the solution is always non-unique and there will be an equivalent solution where the generator is not isolated. A generator that is turned off and connected to the network by a radial line is equivalent to a generator that is turned off and isolated from the network. Therefore, if it is ever beneficial and N-1 feasible to isolate a generator from the network, the same solution can always be obtained by leaving the generator connected to the network via a radial line; thus, there is no reason to isolate a generator from the network.

It is not possible for any load bus to be isolated from the network by transmission switching, unless there is sufficient generation at that load bus and this generation can withstand all contingencies while meeting the load. The node balance constraints for the no-contingency and the contingency states ensure that all load is met for steady-state and all single contingency states. Therefore, this model does not allow load shedding. There may be load shedding as a result of the one day in ten year outage criteria that is permissible within electric transmission networks but there is no load shedding as a result of the transmission switching.

There is the possibility of the new topology creating islands; however, this again cannot happen unless the islands are individually N-1 compliant and operate at least cost. At times, islanding may be beneficial, both from an economic standpoint as well as for reliability reasons. For that reason, this model is preferred since it allows for such beneficial situations while satisfying all N-1 requirements. Contingencies may also create islands; this is possible as long as each individual island satisfies all constraints.

B. Decision Making, Pricing, and Settlements

Since the model is a MIP, the dual problem is not well-defined. By setting the integer variables to their values in the best solution found, the resulting problem is a linear program and the resulting dual is well defined [25].

Since there are constraints reflecting the contingencies and steady state operations, each bus has $N+1$ node balance equations (3) and each equation has a corresponding shadow price, or dual variable. Let λ_{nc} represent the dual variable of (3) for bus n and state c. The LMP for bus n, shown by (13), is then equal to the sum, over all c, of the dual variables from (3) for bus n. This includes the steady-state dual variable, i.e., $c=0$, and all of the contingency dual variables, i.e., $c>0$

$$\mathrm{LMP}_n = \lambda_n = \sum_c \lambda_{nc}, \quad \forall\, n. \tag{13}$$

We assume a nodal pricing system. Generators have linear costs and the generation cost is the total system production cost. Generator revenue is the generator's LMP times its output. The generation revenue is the sum of all generator revenues. Generation rent, or short-term generation profit, is the generation revenue minus generation cost. Congestion rent is the sum of all transmission elements' individual congestion rent, which is calculated as the difference in LMP across the transmission element times the power flow. Load payment is defined as the sum of all load times its LMP.

III. Modifications and Heuristics for Computational Testing

A. Model Modifications for Computational Testing

Transmission switching adds substantial computational complexity to an already difficult problem. Since much of the data to implement the full model presented in Section II is not available in literature, we simplify the model to focus on transmission switching. For initial testing purposes we simplify the problem by dropping the start up costs or investment costs and we set the failure probabilities to zero to focus on whether there are savings from transmission switching when the system must survive any single contingency. We examine two test problems, the IEEE 118-bus and the IEEE 73-bus test cases.

The chosen min and max bus angle values are ± 0.6 radians and this applies to all states. It is computationally conducive to have M_k be as small as possible; the smallest value it can be without imposing any additional restrictions on the bus angles is $\left|B_k\left(\theta_0^{\max}-\theta_0^{\min}\right)\right| = 1.2\,|B_k|$. A similar optimization model is used for transmission expansion in which they formulate a shortest path problem to determine the minimum M_k value; see [26]. The shortest path problem determines M_k by analyzing all possible paths between buses n and m. These paths are maintained if the original topology is not altered; since transmission switching alters the topology, the paths may not be retained. The M_k value would then depend on the chosen topology, thereby making it a variable and requiring the shortest path problem to be solved for each possible topology. This would significantly complicate the problem. As a result, it is conducive to model the bus angle constraints by (2) as then there is no need for this shortest path problem. Based on (2), it is then possible to define M_k as we previously stated.

For any contingency, i.e., $c>0$, the thermal ratings for transmission elements are based on the emergency ratings, or rate C. The generator min and max operating levels are set at their respective min and max levels during steady-state operating conditions for all contingencies.

Since it is a single period model, the generator unit commitment variables, z_g, are removed from the formulation and the model does not incorporate generator ramp rates. When there is a generator contingency, the system is allowed to be re-dispatched in order to meet load during this contingency; a committed generator can be re-dispatched at any level while satisfying $(7')$. The associated cost of this re-dispatch is not included in the objective function since the failure probabilities are set to zero. Since the probability of an outage is low, we are concerned with feasibility of surviving a contingency and less concerned about the cost of operating during a contingency. When there is a transmission contingency, generators must maintain their steady-state operating level. Thus, there are no new generator dispatch variables for transmission contingencies. For the test

TABLE I
CPU SPECIFICATIONS

	Type 1	Type 2	Type 3
No. processors	2	2	4
CPU speed	3.4 GHz	2.8 GHz	2.8 GHz
Total memory	1.0 GB	2.1 GB	2.1 GB

problems, (1), (2), (3), and (7) have been modified; (4), (5a), (5b), and (6) are the same and (8) and (9) have been removed

$$\text{Minimize}: \ \text{TC} = \sum_g c_{ng0} P_{ng0} \quad (1')$$
$$\theta_0^{\min} \le \theta_{nc} \le \theta_0^{\max}, \quad \forall\, n, c \quad (2')$$
$$\sum_{\forall k|i=n} P_{ijkc} - \sum_{\forall k|j=n} P_{ijkc} + \sum_{\forall g|s=n} P_{sg0} - P_{nd} = 0$$
$$\forall n, \quad c = 0, \text{ transmission contingency states } c \quad (3\text{a}')$$
$$\sum_{\forall k|i=n} P_{ijkc} - \sum_{\forall k|j=n} P_{ijkc} + \sum_{\forall g|s=n} P_{sgc} - P_{nd} = 0$$
$$\forall n, \text{ generator contingency states } c \quad (3\text{b}')$$
$$(4),\ (5\text{a}),\ (5\text{b}),\ \text{and } (6)$$
$$0 \le P_{ngc} \le P_{g0}^{\max} N1_{gc}, \quad \forall\, g, c. \quad (7').$$

B. Hardware and Software Description

The model is written in AMPL, which calls the CPLEX optimizer using its default settings. AMPL has a presolve routine that eliminates redundant and unnecessary variables and constraints. The term "post-presolve" reflects the number of variables and constraints that are not eliminated by this presolve routine. The "post-presolve" problem is then solved by CPLEX using a combination of cut, branch and bound techniques. The computer specifications are listed in Table I.

C. Solution Heuristic Techniques

Transmission switching is an NP hard problem. Without any restrictions on the number of transmission elements that can be opened, after almost 143 h the best found solution provides a savings of only 3.3% and the optimality gap is 60% for the test case presented in Section IV-B. The optimality gap is defined as the difference between the best feasible solution and the greatest lower bound divided by the greatest lower bound. The gap between the linear relaxation of the transmission switching problem and the N-1 DCOPF optimal solution without transmission switching is 66%. Thus, the optimality gap has only improved by 6% after 143 h.

Since this problem is hard to solve, heuristic techniques are needed to speed up the computational time and improve the solution. We introduce (14) into the formulation in order to study multiple solutions as well as to ensure that we find good solutions in reasonable time. We use an equality constraint rather than an inequality constraint as it reduces the number of branch and bound nodes to be searched and, hence, it reduces the computational time. We are not suggesting the use of (14) in a practical setting; it is only used within our computational testing. With (14) being an equality constraint, J represents the number of opened transmission elements within the solution. For $J = 0$, all transmission elements are closed. Transmission elements can be opened by opening the breakers

$$\sum_{k \in K} (1 - z_k) = J. \quad (14)$$

We used a simple heuristic technique, the "iterative" approach, to improve the solution time. It determines the best transmission element to open ($J = 1$); with this transmission element forced open, it finds the next best transmission element to open ($J = 2$), opens it, and the process is repeated.

When we implement the "iterative" approach, we also apply "partitioning." Partitioning takes the set of solutions and divides it into multiple subsets that are mutually exclusive and collectively exhaustive. Each subset contains a different set of possible network topologies and each subset is solved independently of the other subsets. Finally, the overall optimal is determined by comparing the optimal solutions for all subsets. By doing this, we can solve these subsets in parallel, i.e., solve these subsets at the same time on various computers.

Another heuristic approach referenced in this paper is what we call the "intelligent learning" heuristic. Operators can take into consideration past transmission switching solutions. The transmission switching solutions will vary with the changing conditions within the network; however, it is likely that there are a number of specific transmission elements that are commonly chosen to be opened. The operator could then focus on these elements when running the program in order to find good feasible solutions in reasonable time. This is what the intelligent learning heuristic does; it allows only a chosen subset of elements to be switched. More specifically, K is reduced and (14) is replaced with an inequality constraint with H representing the maximum number of transmission elements that can be opened: $\sum_{k \in K} (1 - z_k) \le H$. Of course, for this method to work there must have been previous studies performed on the network or knowledge about the network.

Whatever method or heuristic is used, unless optimality is proven, it is always best to use up whatever time is available. If a heuristic method were to find a good solution and terminate before the timeframe is up, the method should be modified so that it can continue searching for better solutions since there is time remaining.

To solve this problem to optimality, (14) would not be present and K would include all transmission elements.

IV. IEEE 118-BUS TEST CASE—NETWORK OVERVIEW, RESULTS, AND ANALYSIS

A. Network Overview

The IEEE 118 network data presented in [19] does not include generator cost information. The generator cost information used in the IEEE 118 network is taken from [27]. Table II lists the network information for the IEEE 118-bus test case and Table III identifies the variables and constraints for both the basic DCOPF as well as the N-1 DCOPF problem. The generator cost information for this study is relatively low compared to generator costs found in today's bulk power systems; most generators within this model have a cost that is around \$0.50/MWh with a few expensive generators that are over \$1/MWh and one that is up to \$10/MWh. In this paper, we therefore focus on percent savings rather than the dollar value. The average cost of energy for the

TABLE II
IEEE 118 NETWORK DATA

		Capacity (MW)			Cost ($/MWh)	
	No.	Total	Min	Max	Min	Max
Transmission	186	49,720	220	1,100		
Generators	19	5,859	100	805	0.1897	10
Load	99	4,519	2	440		

TABLE III
IEEE 118—LP AND MIP VARIABLES AND CONSTRAINTS

	DCOPF		N-1 DCOPF	
	LP	MIP	LP	MIP
Total Variables:	323	509	63k	63k
Binary Variables:	0	186	0	186
Total Linear Constraints:	628	1000	126k	202k
Total Variables (Post Presolve):	315	492	60k	61k
Binary Variables (Post Presolve):	0	177	0	97
Linear Constraints (Post Presolve):	482	833	98k	137k

N-1 DCOPF solution in Section IV-B is $0.735/MWh. If all generator costs were scaled up by a factor of 50 or 100, the average cost of energy would be more typical of today's markets; however, the optimal solution and percent savings would not change. In order to use a published source, we did not modify the cost information and decided to focus on percent savings.

More binary variables are eliminated by presolve for the N-1 DCOPF formulation than for the DCOPF formulation; there are 177 post-presolve binary variables for the DCOPF whereas there are only 97 for the N-1 DCOPF. With fewer binary variables, the problem is less complex and this may reduce the computational time or it may produce a better solution within a fixed timeframe. Reducing the computational time is crucial for practical implementation of transmission switching.

The IEEE 118-bus test case has a generation capacity that is 130% of the load. For Sections IV-B and C, we assume that two of the generator units are not committed to analyze the case where the capacity is closer to 115% of the load. The uncommitted units are the 550 MW unit at bus 10 (unit 1) and the 136 MW unit at bus 111 (unit 19).

The IEEE 118-bus test case information in [19] does not contain emergency ratings, i.e., rate C, for the transmission elements. We therefore assume that the emergency thermal rating for transmission elements is 125% of the steady state operating limit, i.e., rate A.

A longer version of this paper [21] presents additional studies with further results and discussion. The additional studies include using a 113.6% emergency rating for rate C, as is listed in [27] for the IEEE 118-bus test case, instead of the 125% used for Sections IV-B and C within this paper. There are also additional studies that have all generator units committed whereas for Sections IV-B and C there were two units that were assumed to be not committed. The basic results and conclusions do not change.

B. Results and Analysis—Gen Units 1 and 19 Not Committed

Prior to introducing transmission switching, the system was checked for compliance with the N-1 contingency requirements. Note that radial transmission elements are not subject to reliability standards as defined by FERC.[4] These elements are not included in the N-1 contingency list. The system could not satisfy N-1 standards without modifications; it could not survive the loss of either of the two largest generators as well as any of three key transmission elements. Once these items were removed from the N-1 contingency list, the system was N-1 compliant according to this modified contingency list. The transmission elements and generators removed from the contingency list are listed in Table IV. Since the system is not initially N-1 compliant, the results demonstrate that the initial system reliability level can be maintained while incorporating transmission switching and improving the network efficiency.

[4]ERO Reliability standards, FERC Order 696 [28] (see standard TPL-002).

TABLE IV
ASSETS REMOVED FROM THE IEEE 118 N-1 CONTINGENCY LIST

Non Radial Transmission Elements [Radial Elements]	Generators
(82-83), (89-90), (91-92) [(8-9), (9-10), (12-117), (14-15), (16-17), (18-19), (29-31), (68-116), (71-73), (85-86), (86-87), (110-111), (110-112)]	13, 14

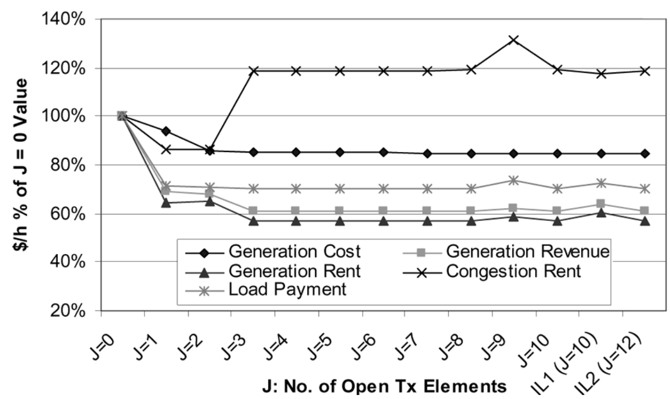

Fig. 1. Costs and settlement payments for the IEEE 118-bus problem.

The N-1 DCOPF optimal solution without transmission switching, i.e., $J = 0$, for this study has an optimal cost of $3323/h; without transmission switching the problem is then the basic N-1 DCOPF, which is an LP. For the no switching $(J = 0)$ solution, the generation revenue is $23 186/h, the generation rent is $19 863/h, the congestion rent is $4467/h, and the load payment is $27 653/h. The LP relaxation of the N-1 DCOPF transmission switching formulation is a lower bound and it has a value of $2006/h for this study, which is roughly 60% of the no switching case $(J = 0)$ optimal solution.

The results presented in Fig. 1 correspond to solutions when performing an iterative approach by finding the next best element to open and two intelligent learning approaches. These techniques do not guarantee an overall optimal transmission switching dispatch but deliver substantial savings. The $J = 10$ solution saves 15% of the generation cost.

The "intelligent learning" heuristic was employed to arrive at solutions IL1 and IL2. Intelligent learning makes use of familiarity with a particular transmission system. In particular, only 20 specific transmission elements for IL1 $(H = 20)$ and 30 for IL2 $(H = 30)$ are eligible for transmission switching. For the IL1 solution, there are ten opened transmission elements; for the IL2 solution, there are 12 opened elements. The transmission elements allowed to be opened for the intelligent learning solutions are based on elements that were opened within the DCOPF solutions from [14]. The results suggest that past information as

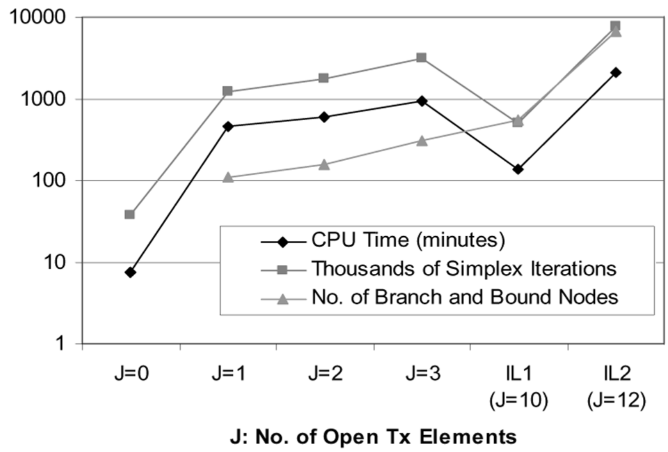

Fig. 2. Computational statistics for the IEEE 118-bus test problem.

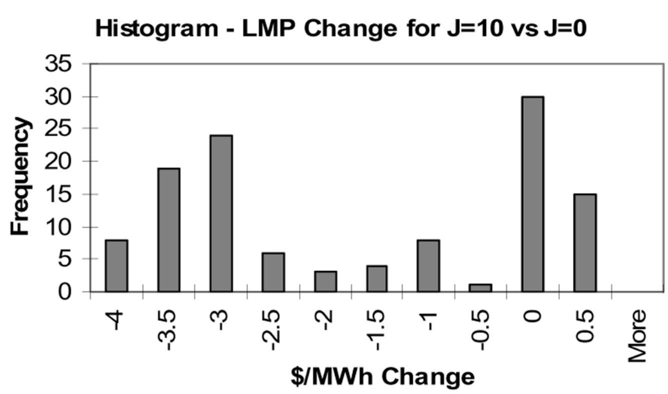

Fig. 3. LMP change for $J = 10$ versus $J = 0$.

well as heuristic techniques can be used to obtain good solutions within reasonable time.

The computational statistics are displayed in Fig. 2 with the units defined within the legend. The computational statistics for solutions obtained by the use of partitioning, $J = \{4 \dots 10\}$, are not presented. The CPU time for the intelligent learning solution 1 (IL1) was 134 min; IL1 produced a 15% savings whereas the $J = 1$ solution took 453 min without the use of partitioning and produced only a 6.3% savings.

The spike in the congestion rent for $J = 9$ is mainly caused by two transmission elements. Both of these transmission elements are connected to a generator bus. In both situations, the generator bus' LMP does not vary significantly whereas the LMP at the bus at the other end of the transmission element does vary. Both of these transmission elements also have significant power flows as well.

A histogram, Fig. 3, presents the change in LMPs comparing solution $J = 10$ to $J = 0$. As can be seen, almost all LMPs decrease with only a few buses having a minor increase in LMP. For $J = 3$ through $J = 9$, the distributions of the change in LMPs are similar to that in Fig. 3. For $J = 1$ and $J = 2$, there are more transmission elements that experience an increase in LMP as oppose to what is shown by Fig. 3.

Basic LMP statistics are presented in Fig. 4. The relatively low LMP throughout all solutions is because a cheap generator cannot produce at its max due to a contingency constraint.

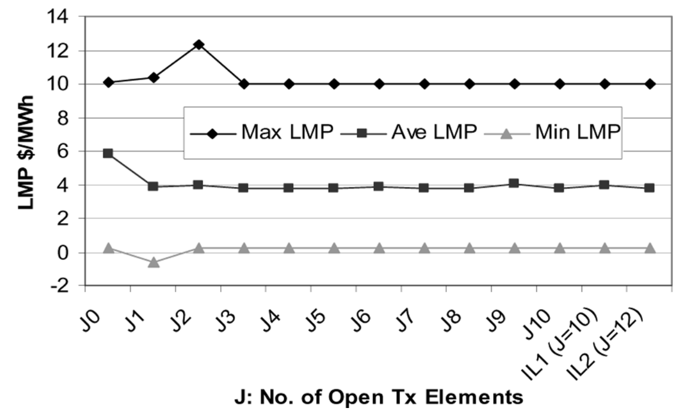

Fig. 4. Max, average, and min LMP.

Very few generators saw an increase in LMP. The largest increase in LMP for a generator was \$0.47/MWh. A few generators saw a large decrease in LMP. There were three generators that had a decrease of \$3/MWh for most of the solutions and one that had a decrease of at least \$5/MWh and up to \$7/MWh for some of the solutions. This largest decrease in a generator LMP corresponds to the largest generator of 805 MW, which was always fully dispatched.

Most load buses see a decrease in LMP but there are a few load buses that see an increase in LMP. Bus 80 experiences the highest increase in load payment, \$60.48/h, for the $J = 2$ solution as the LMP increases by \$0.47/MWh, which is the largest increase in LMP for a load bus for all solutions. All load buses have a decrease in LMP for at least one of the solutions but there is no single solution where all load buses have a decrease in LMP.

C. Results and Analysis at 80% and 90% of Peak Load

This section investigates the impact of transmission switching when the load is reduced by 10% and 20%. For the 20% reduction, the system is N-1 secure except for radial transmission elements. Table IV lists the radial transmission elements for the IEEE 118-bus test case.

When the load is reduced by 20%, the DCOPF solution is only \$4/h greater than the unconstrained economic dispatch solution, leaving little room for improvement from transmission switching [14]. Though the N-1 DCOPF solution is not that close to the unconstrained economic dispatch, the IEEE 118-bus test case does not have a single transmission element that is thermally constrained at the 80% load level. With over 60 000 thermal and bus angle steady state and contingency constraints, only ten of them are active (nine thermal contingency constraints, one bus angle contingency constraint). The $J = 1$ solution produced a savings of only 0.1%. After 19 h, the best found feasible solution for the $J = 2$ solution had a higher total cost than the no switching case $(J = 0)$ N-1 DCOPF solution, i.e., all transmission elements are in service, and the lower bound was 0.2% below the no switching case's $(J = 0)$ solution value.

We also analyzed the IEEE 118-bus test case with the load reduced by 10%. Under this situation, one transmission element needed to be removed from the contingency list as well as one generator in order to obtain an N-1 DCOPF feasible solution without transmission switching. All of the radial transmission

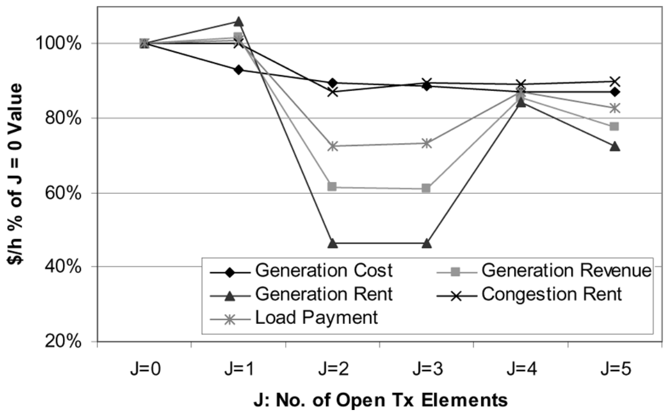

Fig. 5. IEEE 118 results at 90% load.

elements were removed from the N-1 contingency list as well as a transmission element (bus 82 to bus 83) and generator 14.

With a 90% load level, transmission switching achieves similar results to those found for the base load level in the previous section. With this N-1 DCOPF model, transmission switching provides a 13% savings for the best found solution, as is shown by Fig. 5. The generation cost for the no switching case $(J=0)$ is \$1807/h, the generation revenue is \$5174/h, the generation rent is \$3367/h, the congestion rent is \$4013/h, and the load payment is \$9187/h. The LP relaxation of this study has an optimal cost of \$1284/h or 71% of the no switching case $(J=0)$ solution. Further savings may be obtained with further investigation since this best found solution has not been proven to be the optimal solution.

Except for the no switching case $(J=0)$ solution, the solutions presented in Fig. 5 were found by iteratively solving for the next best transmission element to open and by using partitioning. By partitioning the problem into two equally sized branch and bound trees, the computational time was approximately 2.5 h with the partitioned problems solved in parallel (the problems were solved at the same time on different machines). Other solutions were partitioned into 20 sets and took approximately 60 to 90 min to solve sequentially or at most 10 min when solved in parallel.

The generation rent for the $J=1$ solution was higher than the generation rent for the no switching case $(J=0)$; the generation rent for the $J=2$ and $J=3$ solutions is about 50% of the no switching $(J=0)$ generation rent value. The initial increase is caused by the largest dispatched generator having an increase in LMP for the $J=1$ solution but then its LMP decreases for $J=2$ and $J=3$. Another large generator also receives a much lower LMP for the $J=2$ and $J=3$ solutions as well, thereby adding to the decrease in overall generation rent. The LMP for the generator at bus 80 changes from over \$3/MWh for the no switching case $(J=0)$ to about \$0.65/MWh for $J=2$ and $J=3$.

The generator at bus 69 produces at capacity (805 MW) for $J=4$ and $J=5$; it has an LMP of \$1.35/MWh for $J=4$ and \$1.09/MWh for $J=5$. Its generation revenue differs by \$214/h whereas the $J=4$ and $J=5$ total generation costs differ by only \$4/h or 0.2%. It is possible to have solutions that have very similar objective values but have drastically different outcomes for individual market participants, which is consistent with what is discussed in [29] for generation unit commitment methods.

TABLE V
RTS 96 SYSTEM DATA

		Capacity (MW)			Cost ($/MWh)	
	No.	Total	Min	Max	Min	Max
Transmission	120	44,747	175	722		
Generators	111	12,045	12	400	0.00	62.12
Load	51	8,547	53	745		

TABLE VI
FUEL COSTS FOR THE RTS 96 SYSTEM

#2 Oil	#6 Oil	Coal	Uranium
5.781 $/MBtu	4.034 $/MBtu	1.231 $/MBtu	0.60 $/MBtu

V. IEEE 73 RELIABILITY TEST SYSTEM 1996 (RTS 96)—NETWORK OVERVIEW, RESULTS, AND ANALYSIS

A. Network Overview

The IEEE 73-bus network, also known as the reliability test system 1996 (RTS 96), was created by a committee of power systems experts to be a standard for reliability testing [20]. The RTS 96 system includes many different configurations and technologies so that it can represent reliability situations found in most electrical systems.

It is common to make modifications to the RTS 96 system (see for instance, [30] and [31]). In particular, in [30] the authors removed line (11–13), shifted 480 MW of load from bus 14, 15, 19, and 20 to bus 13, and added generation capacity at bus 1 (100 MW), bus 7 (100 MW), bus 15 (100 MW, 155 MW), and bus 23 (155 MW). Buses 14, 15, 19, and 20 had an original total load of 820 MW; the new total load is 340 MW. In [31] the authors decrease the thermal capacity of line (14–16) to 350 MW in order to create congestion. For this study, we modified the RTS 96 system by incorporating the changes mentioned above from [30] and [31]. [5] The RTS 96 system has three identical zones; the modifications for the first zone are listed above and the same modifications are applied to all zones.

Table V provides an overview of the RTS 96 system data. All generators are assigned a minimum operating capacity of 0 MW; the generator cost information is an average cost based on the heat rate data presented in [19] and the fuel cost presented in Table VI. There is seasonal information for the hydro units within the RTS 96 system, all of which are assumed capable of producing at their full capacity. The RTS 96 system includes a yearly load curve. Within Section V-B, the load is set at the values defined from [19, Bus Data Table-01] for the RTS 96 system. Table VII describes the problem size for this study.

Once again, there are fewer post-presolve binary variables for the N-1 DCOPF than the DCOPF. Certain transmission elements cannot be opened while maintaining N-1 standards; thus, the presolve routine fixes these binary variables to 1.

B. Results and Analysis

Unlike the IEEE 118-bus test case, the RTS-96 system is N-1 compliant so the N-1 contingency list includes all elements. Since the RTS system is initially N-1 compliant, these results

[5]Modifications in [30] included reducing the total load of several buses. To determine the new load levels, we calculated each bus' initial percentage of the original total load among these buses and allocated that bus the same percentage of the new total load. For instance, bus 14 had 23.7% of the 820 MW of the original total load and now has 23.7% of the new total load.

TABLE VII
RTS 96—LP AND MIP VARIABLES AND CONSTRAINTS

	DCOPF		N-1 DCOPF	
	LP	**MIP**	**LP**	**MIP**
Total Variables:	304	424	57k	57k
Binary Variables:	0	120	0	120
Total Linear Constraints:	498	738	102k	158k
Total Variables (Post Presolve):	301	421	57k	57k
Binary Variables (Post Presolve):	0	117	0	89
Linear Constraints (Post Presolve):	307	542	72k	75k

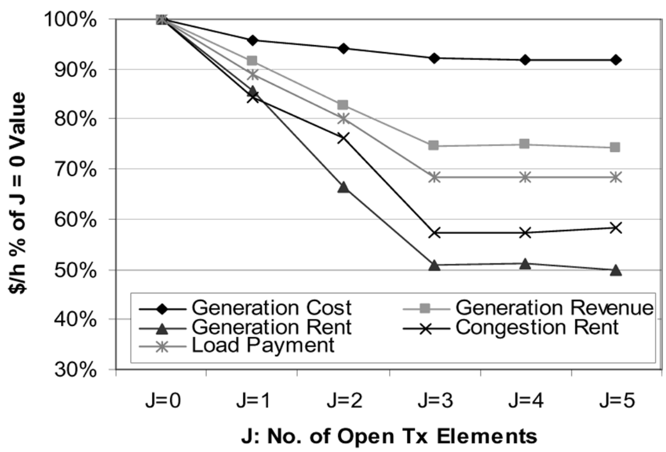

Fig. 6. Costs and settlement payments for the IEEE RTS 96.

demonstrate that transmission switching can improve the efficiency of an N-1 compliant system and maintain an N-1 secure network. The results are presented by Fig. 6.

The best found solution, $J = 5$, provides a savings of 8% from transmission switching for the N-1 DCOPF model. For a DCOPF model, there is almost no savings from transmission switching thereby demonstrating that it is possible to obtain a higher percent savings with a more constraining OPF model. The longest solution took 20 min with most taking about 10 min. The no switching case $(J = 0)$ solution has a generation cost of \$106 k/h, the generation revenue is \$184 k/h, the generation rent is \$78 k/h, the congestion rent is \$109 k/h, and the load payment is \$293 k/h. The LP relaxation has an optimal cost of \$85 k/h or 80% of the no switching case $(J = 0)$ optimal solution.

There are multiple generators that are producing in the no switching case $(J = 0)$ but are not producing once the topology is changed and vice versa. Previous results showed that there could be significantly different outcomes for market participants between two solutions that have objectives that differ by a small amount. For this study, most buses have LMPs that are very similar for $J = 4$ and $J = 5$ but there are a few buses that see an LMP change that is greater than \$5/MWh. Some of the buses with the large LMP change are load buses but none are generator buses.

Bus 38 has a load of 80 MW and has the second highest LMP for the no switching case $(J = 0)$ with an LMP at \$84.98/MWh. For the $J = 1$ and $J = 2$ solutions, it experiences one of the largest LMP increases for these two solutions. Most large increases in LMP are at load buses that initially had much lower LMPs for the no switching case $(J = 0)$ solution. Bus 38 has a large increase in LMP when it had the second highest LMP for the no switching case $(J = 0)$. However, for the $J = \{3, 4, 5\}$ solutions, bus 38's LMP decreases by \$60/MWh down to about \$20/MWh.

A longer version of this paper [21] presents additional studies including different assumptions on how the network is modified as well as changing the load level. The basic results and conclusions do not change.

VI. FUTURE WORK

Future research should investigate dynamic load patterns to investigate the effects of transmission switching over time since lines affect reactive power profiles differently under different loading patterns. Transmission switching may also provide savings by relieving the requirement to start up a generator under certain circumstances, thereby saving the start up costs. A generation unit commitment model should also be built into future work to examine such possibilities. There is also the need to research the impacts from transmission switching regarding real time operations including voltage problems, reactive power, transient stability, etc. This analysis is necessary at varying load levels as well since the capacitive component of a transmission element is predominant during low load levels whereas the reactive component is predominant at higher load levels.

Heuristic methods like the "intelligent learning" heuristic require studies to be performed in advance in order to determine appropriate parameters for the heuristic to be useful and provide savings. Future research could investigate the best ways to determine these parameters. Testing the model on large scale, practical networks is needed as well [32].

VII. CONCLUSIONS

As computing power and optimization techniques improve, the multi-trillion dollar electric industry looks for ways to cut costs by taking advantage of these improvements. Viewing transmission elements as committable assets in an optimization framework is relatively new as such analysis was not possible in the past due to the added complexity to an already challenging problem. As computing power increases and the software improve, potential savings may be in the tens of billion dollars by improving the dispatch and by making better investments.

There are concerns with whether transmission switching will be a detriment to reliability and stability. We have demonstrated that a network can satisfy N-1 standards while cutting costs by incorporating transmission switching into the dispatch. Significant savings for the IEEE 118-bus test case were obtained due to transmission switching, savings as high as 15% of the generation cost with an N-1 DCOPF model. These savings are not as high as savings found in earlier work that showed a savings of 25% with a DCOPF model [13]. However, the 15% savings found are still significant. Savings of 8% for the RTS 96 system were obtained with the N-1 DCOPF model.

Our work thus far has shown significant savings from transmission switching. If the savings are even half of what we are currently finding, such savings would still be substantial. These findings suggest that further research on transmission switching is justified for larger networks and with more granular modeling, such as an ACOPF.

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