Optimal Transmission Switching in Electric Networks for Improved Economic Operations[1]

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1. Abstract

Growing demand for electric power seems to necessitate new transmission lines, but obstacles to building these new lines are often extremely high. At the same time there is a national push for a "smarter" bulk electric grid, one that is more controllable and flexible. Optimal transmission switching is a straightforward way to leverage grid controllability: to make better use of the existing system and meet growing demand with existing infrastructure.

In this paper we present the formulation for an Optimal Power Flow with optimal transmission switching. Using this formulation to dispatch generators, we demonstrate system savings both on benchmark networks, such as the IEEE 118 bus system, and large-scale networks, including the ISO-NE and CAISO systems. Savings found here range from 13% to 25%, which, in a multi-trillion dollar industry, can mean substantial savings. In addition, market settlements based on OPF with transmission switching are examined and discussed. We also present the formulation for, and savings possible with, a security-constrained OPF with optimal transmission switching—a more secure, if not more restrictive, formulation.

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2. Introduction

Electric networks are unique among networks. Because of the fundamental physics that govern electrical networks, the physical characteristics and the flow on each line impact flow on all lines. It is therefore possible to remove a link in order to improve the throughput of the system.

Traditionally, transmission networks for bulk power flow have been considered static infrastructure, a “superhighway” for power delivery. However, switching transmission lines is a common practice done with a mature technology. Circuit breakers are used to open and close transmission lines. System operators can, and do, change the topology of systems to improve voltage profiles or increase capacity of a flowgate. Anecdotal evidence exists that some system operators switch lines in and out because of reactive power consumption or production of lines, or other reasons. The Northeast Power Coordinating Council includes “switch out internal transmission lines” in the list of possible actions to avoid abnormal voltage conditions (Northeast Power Coordinating Council, 1997) (ISO-NE, 2007). In addition, system operators have procedures in place to close lines quickly in case of emergency. In PJM, these Special Protection Schemes (SPSs) allow the operator to disconnect a line during normal operations but return it to service during a contingency. Transmission switching has been explored in the engineering literature as a control method for problems such as over- or under-voltage situations, line overloads (Granelli et al., 2006), loss and/or cost reduction (Schnyder & Glavitsch, 1990), improving system security (Schnyder & Glavitsch, 1988), or a combination of these (Bacher & Glavitsch, 1986) (Rolim & Machado, 1999) (Shao & Vittal, 2005). Transmission switching for economic benefit in a market context was investigated by O’Neill *et al.* (2005).

Transmission infrastructure is expensive and extremely hard to site (Vajjhala & Fischbeck, 2007), yet, as the current system is aging and being used closer to its capacity, the need for new or upgraded transmission network has become a priority. Recently, improving controllability and flexibility of the bulk transmission grid has become a research and political priority. July 2007, US Senator Boucher introduced HR Bill 3237 with the stated purpose of “facilitat[ing] the transition to a smart electricity grid.”[7] The bill states eleven characteristics of a smart grid, including “dynamic optimization of grid operations,” and “enhanced capacity and efficiency of

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[7] See Title I, SEC.101.a and SEC.102.a.2 of HR Bill 3237 of the 110th Congress.

electricity networks." The US Energy Policy Act of 2005 also includes a directive for federal agencies to "encourage…deployment of advanced transmission technologies," including any technology "that increases the capacity, efficiency, or reliability of an existing or new transmission facility."[8] The Act identified "optimized transmission line configuration" as one possible goal.

Optimal transmission switching is a promising option because it uses existing and familiar technology – circuit breakers – to achieve important and timely goals – increased grid flexibility and efficiency. In this paper, we examine the potential for switching to increase the economic efficiency of power system dispatch by embedding switching decisions within the system dispatch model and optimizing the transmission topology simultaneously with generator output.

To embed these decisions, we incorporate transmission switching into the standard optimal power flow program used to dispatch generators in power networks. Adding transmission switching to this problem introduces non-continuous variables (e.g. a line is either open or closed), which are modeled with binary variables. The result is that the linear OPF model becomes a mixed-integer problem (MIP), which can be much more difficult to solve.

While the goal of solving an optimization problem is to find an optimal solution, solving MIPs can be difficult (e.g. take a very long time and be dependent on how the computer solver looks for a solution). Therefore, in some of the following analysis we talk about the best found solution or best feasible solution rather than the optimal solution. While finding a unique optimal solution and improving solution time are interesting academic and computational issues, the fact that an optimal solution is not always found in this initial research is not a problem. The important discovery here, and for practical markets, is that an *improved* solution is possible by using optimal transmission switching.

The optimization problem used to solve the dispatch problem uses generation cost (and when appropriate, consumer willingness to pay) as the objective function. This choice is based on economic theory, which says maximizing social welfare—the difference between consumer demand and generator cost curves—is desirable because it results in efficient production and trade.[9] This objective is a valid one for both regulated systems, where generation dispatch is a centralized process in which all operating costs are known, and for market-based systems, where

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[8] See SEC.1223.a.5 of the US Energy Policy Act of 2005.

[9] In cases where demand is fixed, maximizing social welfare is equivalent to minimizing generator cost.

dispatch is determined by a centralized grid operator who takes bids from generators and depends on those generators to operate as directed.

Cost savings from transmission switching can be realized in both regulated and market systems. The difference lies in payments and cash flow. In regulated systems, generators, transmission lines and loads are all owned and managed by the same entity, and thus money is not really changing hands: generators are essentially "paid" the cost of operating (or rather the central utility is paying the fuel costs, worker salaries, etc., directly). In a market system, however, generators are not paid their costs, but rather the nodal prices at the point of interconnection.[10] The nodal price at each node (or bus or connection point) in the system is the value of a marginal change in demand at that node. This value is easy to get from the optimization solution used for dispatching the system: nodal prices are simply the dual variables on the power balance constraints. In markets, therefore, payments to generators can be different than their cost. In other words, minimizing generator cost is guaranteed in the solution, but there is no indication of what happens to nodal price, and thus payments to and from market participants. To analyze these changes, we must look at nodal prices as well.

In the following sections we present the modified optimal power flow optimization problem to include transmission switching, and apply this to a test network model to explore the potential for improving system dispatch cost and the resulting effects on economic rents for generators and loads. We also formulate and analyze an N-1 contingency, and examine the solution of optimal transmission switching when it is applied to an ISO network model. Practical implications of transmission switching are discussed.

3. Optimal Transmission Switching: Formulation

Currently, power systems are dispatched, or generation is scheduled to meet demand, by using an optimization model called an Optimal Power Flow (OPF). The OPF minimizes generator cost (or minimizing generator bids, or maximizing social welfare, depending on the market structure)

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[10] Nodal payments to generators is now widely accepted in the US, and in the so-called "Day 2" markets day ahead and real-time markets are settled at nodal prices. This was not always the case in the US, and currently European markets are still considering zonal payments to generators.

subject to the physical constraints of the system. These constraints include limits on nodal voltage angles (constraint (1) in the formulation below), minimum and maximum capacity limits of generators (constraint (2)), and maximum flow capacity limits of transmission lines (constraint (3)). In addition, power balance at each node is enforced by constraint (4), and the DC approximation of Kirchhoff's voltage laws are incorporated in constraint (5). All variables and parameters are defined in the appendix.

This formulation is the so-called "DC" approximation; it is commonly used instead of the more complex "AC" model because it is linear. This formulation is very general, and can be expanded to include any other constraint or objective function that would represent the system more accurately.

Traditional OPF Formulation

$TC = Min\sum_{g} c_{ng} P_{ng}$

$s.t.$:

(1) $\theta_n^{\min} \le \theta_n \le \theta_n^{\max}$ for all n

(2) $P_{ng}^{\min} \le P_{ng} \le P_{ng}^{\max}$ for all g and n

(3) $P_{nk}^{\min} \le P_{nk} \le P_{nk}^{\max}$ for all k and n

(4) $-\Sigma_k P_{nk} - \Sigma_g P_{ng} - \Sigma_d P_{nd} = 0$ for all n

(5) $B_k\left(\theta_n - \theta_m\right) - P_{nk} = 0$ for all lines k with endpoints n and m

The result of running this optimization problem is the optimal generator output for the fixed level of load. If load were price-responsive, it could be modeled as a variable, and the objective function would then be to maximize the difference between what consumers are willing to pay and the cost of generation.

To modify this formulation to represent transmission switching, a vector of binary variables is added that represent the status of each transmission line. When a transmission line is opened, two things happen: no flow is allowed over the line, and that line needs to be removed electrically from the network, so that it no longer impacts flows on other lines. If the flow were only limited to zero, the network model would continue to enforce the laws relating every flow to every line in the network, and would seriously constrict flow on the whole network. Put another way, this would be equivalent to having one line in a network with an extremely small capacity constraint: almost no power could flow on that one line and that limit would affect flow on all other lines as well. Therefore, to model transmission switching correctly, several constraints must be modified. First, the minimum and maximum transmission capacity constraints are multiplied by the binary variables in the constraint defining transmission flow limits (constraint (3), now (3’)). This limits the flow over that line to zero. Second, the constraints representing the network relationships are changed so if a transmission line is closed (or active in the system) the constraint does not change, but if the line is open the link between bus voltage angles and line flow is suspended (constraint (5a’) and (5b’)). In these constraints the M_k value is simply a large number, larger than $\mathrm{B}_\mathrm{k}\left(\theta_\mathrm{n}^{\max}-\theta_\mathrm{m}^{\min}\right)$. If $z_k = 1$ (line is closed) the constraints (5a’) and (5b’) collapse into constraint (5) from the original, ordinary OPF. If $z_k = 0$, the flow on the line, P_{nk}, does not have to equal $\mathrm{B}_\mathrm{k}\left(\theta_\mathrm{n}^{\max}-\theta_\mathrm{m}^{\min}\right)$. This removes that transmission line electrically from the network.

OPF Formulation with Transmission Switching[11]

$TC = Min \sum_g c_{ng} P_{ng}$

s.t.:

(1) $\theta_n^{\min} \le \theta_n \le \theta_n^{\max}$ for all *n*

(2) $P_{ng}^{\min} \le P_{ng} \le P_{ng}^{\max}$ for all *g* and *n*

(3’) $P_{nk}^{\min} z_k \le P_{nk} \le P_{nk}^{\max} z_k$ for all *k* at nodes *n*

(4) $-\Sigma_k P_{nk} - \Sigma_g P_{ng} - \Sigma_d P_{nd} = 0$ for all *n*

(5a’) $B_k\left(\theta_n - \theta_m\right) - P_{nk} + \left(1 - z_k\right)M_k \ge 0$ for all lines *k* with endpoints *n* and *m*

(5b’) $B_k\left(\theta_n - \theta_m\right) - P_{nk} - \left(1 - z_k\right)M_k \le 0$ for all lines *k* with endpoints *n* and *m*

(6’) $\sum_k \left(1 - z_k\right) \le j$

Constraint (6’), also called a generalized upper bound constraint, is used only for analysis purposes; it limits the number of transmission lines that can be open for any given solution.

4. IEEE 118-bus Network Results

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[11] Formulation originally presented in Fisher, O'Neill, & Ferris (2008).

The formulation presented above was used to dispatch a common engineering test case: the IEEE 118 bus network. This commonly used network is based on a portion of the AEP network from 1962, and was chosen for this analysis precisely because it is a well-accepted model in the engineering community. Data for the test system was obtained from the University of Washington Power System Test Case Archive, and transmission line characteristics and generator variable costs were taken from [16].

System Dispatch Cost

The system comprises 118 buses, 186 transmission lines, 19 committed generators with a total capacity of 5,859 MW, and 99 load buses with a total consumption of 4,519 MW. The solution to the original OPF with no-switching is $2,054/h. The variable costs behind this solution range from $0.19/MWh to $10/MWh, which are on the order of 50 to 100 times smaller than typical generator costs; more realistic generator costs would result in a higher operating cost.[12] Two lines out of the total of 186 are fully loaded, or congested, in the no-switching dispatch.

The system dispatch was then solved using the optimal transmission switching formulation. With no limit on the number of lines open (e.g. constraint (6’) not included), the best solution reduced the operating cost by nearly 25 percent, or $511/h, over the case with no switching. Thirty-eight lines were open in this solution.

To gain better understanding of this solution, constraint (6’) was added and the optimal solution was found for j = 1, …,7; resulting dispatch costs are shown below in Figure 1. As is evident from this figure, in this particular case the majority of achievable savings are obtained by opening just a few lines.

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[12] We chose to not modify these costs because we wanted to be consistent with values that appear elsewhere in the literature.

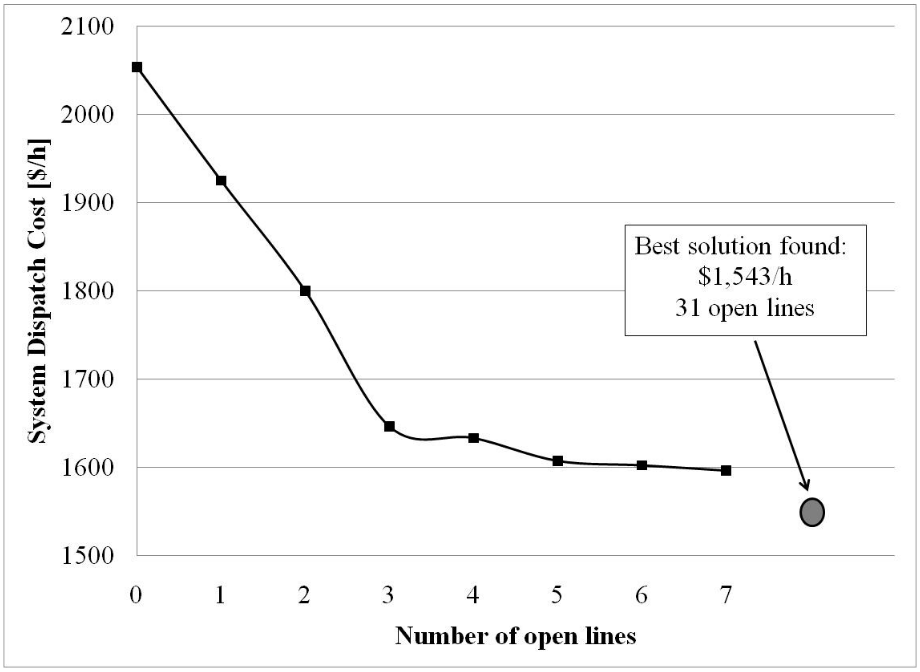

Figure 1. System Dispatch Cost, IEEE 118-bus model

System Prices

In a market setting, generators are paid the nodal price for the amount of power they produce. As the dual variables on the power balance constraint in the optimization problem, nodal prices represent the value of a unit of power at each point in the network. It is not surprising, therefore, that they will change when the transmission topology and generation dispatch change.

The total values of generator cost and revenue, load payments, and transmission congestion rent (calculated as the difference in nodal prices at the two end nodes times the flow across the line) for the no switching case are shown in Table 1 below.

Table 1. Total System Values with No Switching, IEEE-118 bus

Total Generator Cost	$2,054
Total Generator Payment	$3,850
Total Load Payment	$7,757
Total Congestion Rent	$3,907

In Figure 2 below, total generator cost and payments, load payments, and transmission congestion rent are shown for solutions j = 0,…,7 for the IEEE 118-bus model. Generator cost, shown as the line in the figure, is strictly decreasing. This is to be expected because minimizing generator cost is the objective function. The other values—payment to the generators, from loads, and for transmission congestion—do not follow a pattern. For improved generator cost each can be higher or lower than for the original case or other switching cases.[13]

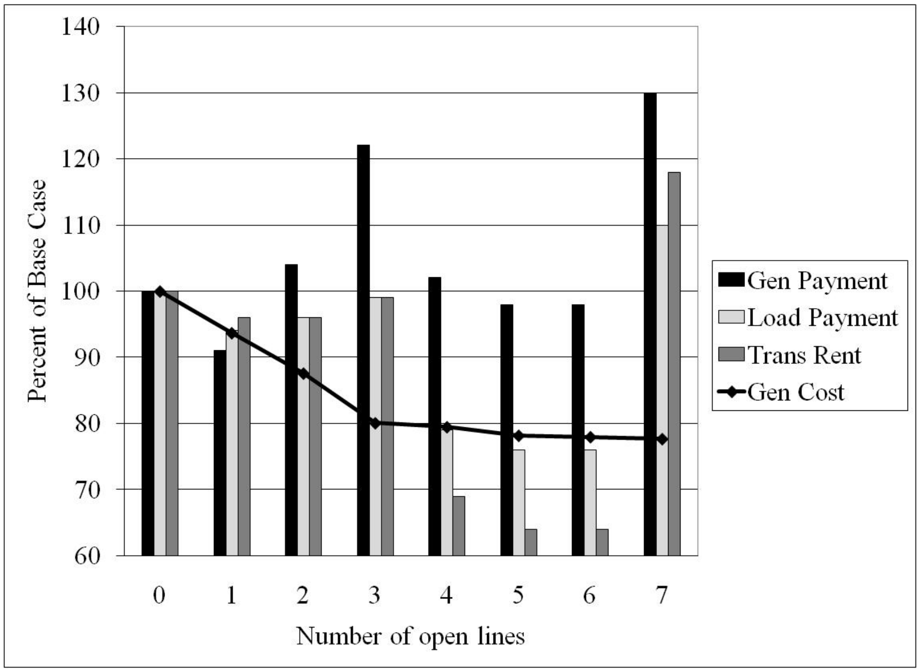

Figure 2. Total System Payments, IEEE 118-bus model

Not only are the total payments volatile, but the price at an individual node can change substantially for each transmission switching solution. In Figure 3, the average, minimum and maximum changes in nodal price are shown as compared to the no switching case. The average change in nodal price seems to be reasonable, only a few percent change, except in case j=7 where the average increases by 60%. However, for buses that do experience changes in price, they can be quite substantial. For j=4, for example, the price at one bus changes by 200% from the no-switching case. For j=7, the maximum change in nodal price was over 2000%, dwarfing the other cases; for scale reasons it was not included in the chart.

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[13] For a more detailed analysis, see Hedman et al. (2008a).

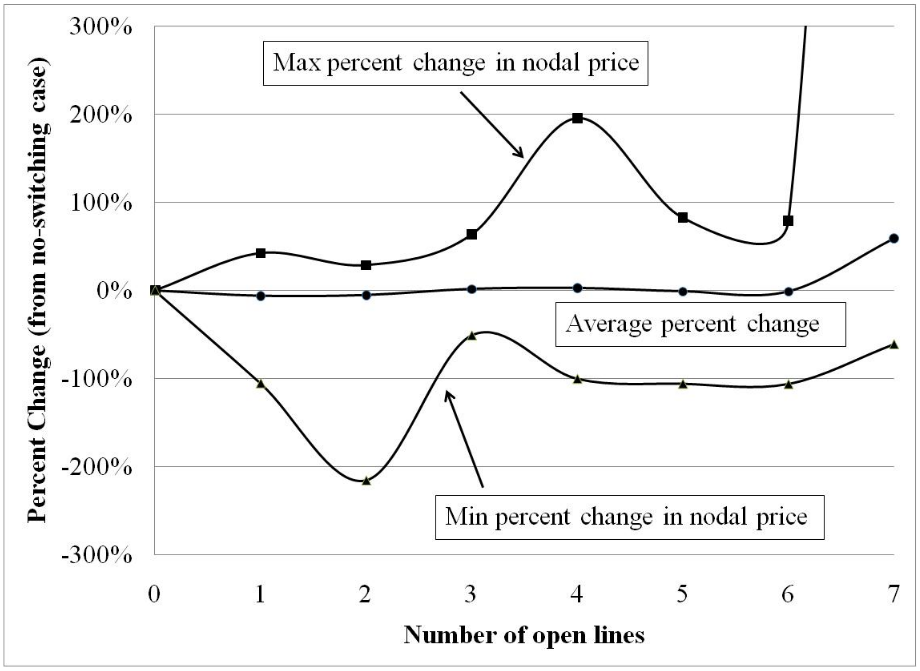

Figure 3. Changes in Nodal Prices, IEEE 118-bus model

The volatility is substantial, but for market participants that hedge their short-term positions in forward markets, this volatility should not have a large financial impact. Also, the changes in nodal prices and total payments depend entirely on the system under consideration: great volatility was found for the IEEE 118-bus case, but this tells us nothing about how prices may change for other networks.

Value of Flexibility

With a system cost saving of 25%, we were lead to wonder whether this transmission topology was somehow inherently inefficient. To test this, we decreased the load levels by 10% in the test network and ran the dispatch with optimal switching again for the cases j=1, …, 4. We found that in fact different lines were opened in the low-load case than were opened in the original load case. Table 2, below, shows the transmission line identification number that was opened in the solution to the dispatch problem with switching for j=1,…,4 for both the original case and the low-load case. While there are a few overlaps, for the most part each optimal solution contains a different set of open lines.

Table 2. Optimally Open Lines for Original and Low-load Cases

j	Optimally Open Lines for Low-load Case	Optimally Open Lines for Original load Case
1	132	153
2	132, 136	132, 153
3	64, 132, 136	132, 136, 153
4	64, 131, 132, 133	132, 136, 153, 162

We then compared the system dispatch cost of solving the low-load case with fixing the transmission line status to match the original case and running a dispatch for the low-load case with no additional switching. This was to examine how much value is in the ability to make switching decisions flexibly, in order to meet actual system conditions. As can be seen in Figure 4, determining transmission topology specifically for existing system conditions has benefit, and that a transmission network optimized for one particular pattern of load on a network is not necessarily optimal for another.

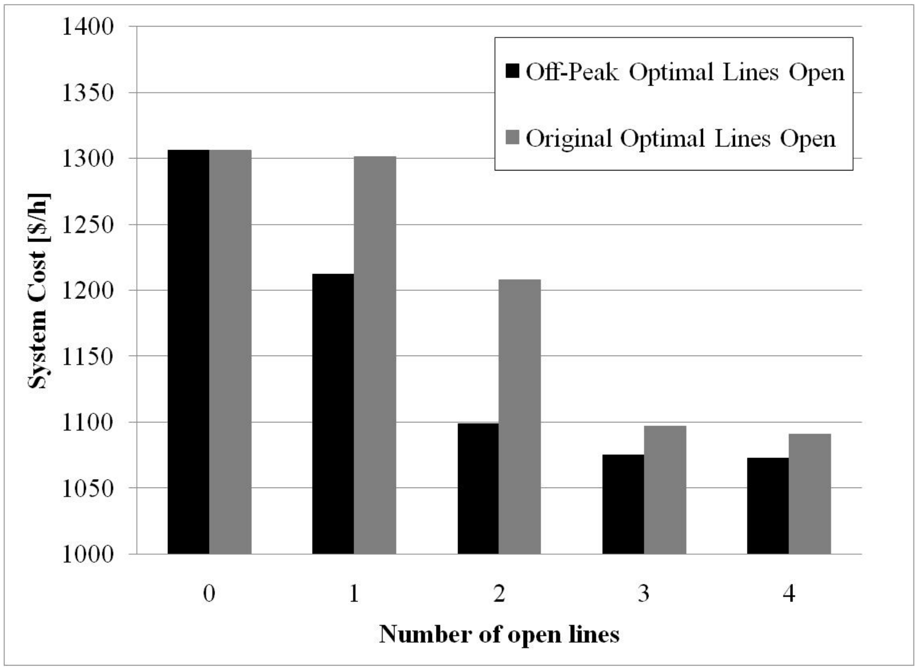

Figure 4. System cost for Low-load Case with Flexible and Fixed Transmission Topology

This preliminary analysis suggests that transmission switching can add value to a system, but there is much to look at before declaring victory. We now address two important questions: (1)

Can a system maintain reliability and benefit from transmission switching? and (2) Will benefits to actual networks be comparable?

5. Reliability and the N-1 Contingency Analysis

A reliable system is one that can survive unexpected operating conditions, in particular unexpected generator or transmission outages. Often redundancies are built into electric networks in order to survive outages, for instance, having parallel transmission lines or highly meshed networks. A concern with optimal transmission switching has been that it may be precisely these redundancies that are being targeted and removed to improve economic efficiency.

A transmission or bulk power system is only reliable if it is operated in a reliable manner; a given transmission network cannot be said to "be reliable", unless the demand, generation and power flows on that system are also known to be reliable. A given transmission topology could be operated in a reliable way or an unreliable way. We argue that there is nothing inherently unreliable about optimal transmission switching, and that this practice could be incorporated in a reliable way. The main question, then, is when this switching is done in a reliable way does it still improve the economic efficiency of the system. In order to explore this, we formulated an N-1 contingency OPF with transmission switching and use it to dispatch the IEEE 118-bus test network. An N-1 contingency analysis is one where every contingency (outage) that the operator decides the system should survive is explicitly modeled in the dispatch problem. Our formulation of this problem is presented below, and results are discussed.

N-1 Formulation

The N-1 formulation contains the same equations and objective as the original optimal transmission switching problem described above, but adds constraints representing the loss of any single element in the system: a transmission element or generator. Each constraint must now be included not only for each actual instance of the physical element (e.g. a transmission line limit constraint for each transmission line) but be repeated for each possible contingency configuration of the network. For example, if there were 10 generators and 15 transmission lines there would be 26 sets of complete constraints, one for the no contingency instance, and 25 for each contingency network (each of those 25 would be missing one generator or transmission line: the contingency element).

N-1 Contingency OPF Formulation with Transmission Switching[14]

$TC = Min\sum_{g} c_{ng0} P_{ng0}$

$s.t.:$

(1'') $\theta_n^{\min} \le \theta_{nc} \le \theta_n^{\max}$ for all n and c

(2'') $0 \le P_{ngc} \le P_g^{\max} N1_{gc}$ for all g and $N1_{gc}$

(3'') $P_{kc}^{\min} z_k N1_{kc} \le P_{nkc} \le P_{kc}^{\max} z_k N1_{kc}$ for all k and c

(4a'') $-\sum_{k} P_{nkc} - \sum_{g} P_{ng0} - P_{nd} = 0$ for all n and $N1_{kc}$

(4b'') $-\sum_{k} P_{nkc} - \sum_{g} P_{ngc} - P_{nd} = 0$ for all n and $N1_{gc}$

(5a'') $B_k(\theta_{nc} - \theta_{mc}) - P_{nkc} + (2 - z_k - N1_{kc})M_k \ge 0$ for all k and $N1_{kc}$

(5b'') $B_k(\theta_{nc} - \theta_{mc}) - P_{nkc} - (2 - z_k - N1_{kc})M_k \le 0$ for all k and $N1_{kc}$

(5c'') $B_k(\theta_{nc} - \theta_{mc}) - P_{nkc} + (1 - z_k)M_k \ge 0$ for all k and $N1_{gc}$

(5d'') $B_k(\theta_{nc} - \theta_{mc}) - P_{nkc} - (1 - z_k)M_k \le 0$ for all k and $N1_{gc}$

(6') $\sum_{k}(1 - z_k) \le j$

We assume that generators are not re-dispatched in response to a transmission line outage, but that there is generation re-dispatch in response to a generator outage. Generators must adjust their output to a generator outage because otherwise there would not be enough generation to meet all load (without load-shedding, of course, which we do not allow). Thus, there is a new generation dispatch variable (P_{ngc}) for each G-1 contingency. Change in unit commitment is not considered for contingency instances. Generator ramp rates are also not included, so in response to an outage a generator can produce anywhere from zero to its maximum output. During contingencies it is assumed transmission lines can be operated at 125% of their normal operating capacity.

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[14] Formulation originally presented in Hedman et al. (2008b). Note that solution time is improved if constraints (5a'') – (5d'') are reformulated using indicator constraints, essentially removing these constraints from the problem when either the line is switched open or modeled as having an unexpected outage.

The associated cost of generation re-dispatch in response to a contingency is not included in the objective function: the probability of an outage is so low that we are concerned here with the *ability* to survive a contingency, not with minimizing the cost of surviving a contingency.

System Dispatch Cost

To use this N-1 contingency optimization on the IEEE 118-bus network, we had modify the original case (where no transmission lines are switched out) in order to survive N-1 contingencies. The way it was, the system could not survive the loss of the two largest generators (out of 19 total) and three transmission lines (out of 189). Removing these five elements from the contingency list was sufficient to obtain a feasible solution.

The dispatch cost for the N-1 compliant case with no transmission switching was \$3,323/h. Because of the size of the problem, we were not able to run the switching problem with no limit on the number of lines open. To find solutions within a reasonable time the optimization was run with j=1 to identify the line that made the largest improvement. That line was then fixed open and the optimization was solved again with j=1. These solutions are shown below in Figure 5. The best solution was \$2,825/h, a 15% savings over the N-1 case with no transmission switching. Although the \$2,825/h solution was not proven optimal it is a substantial improvement over the original dispatch cost. The savings appear to be reaching a plateau, indicating that the majority of the total possible savings are achieved by opening just a few lines.

System Prices

Changes in nodal prices occurred in the N-1 contingency transmission switching, but not the same high volatility as was seen in the previous case. As more lines are opened, the generator cost decreases (as is expected), but generator revenue and load payments also decrease. Congestion rent across transmission lines initially decreases and then increases.

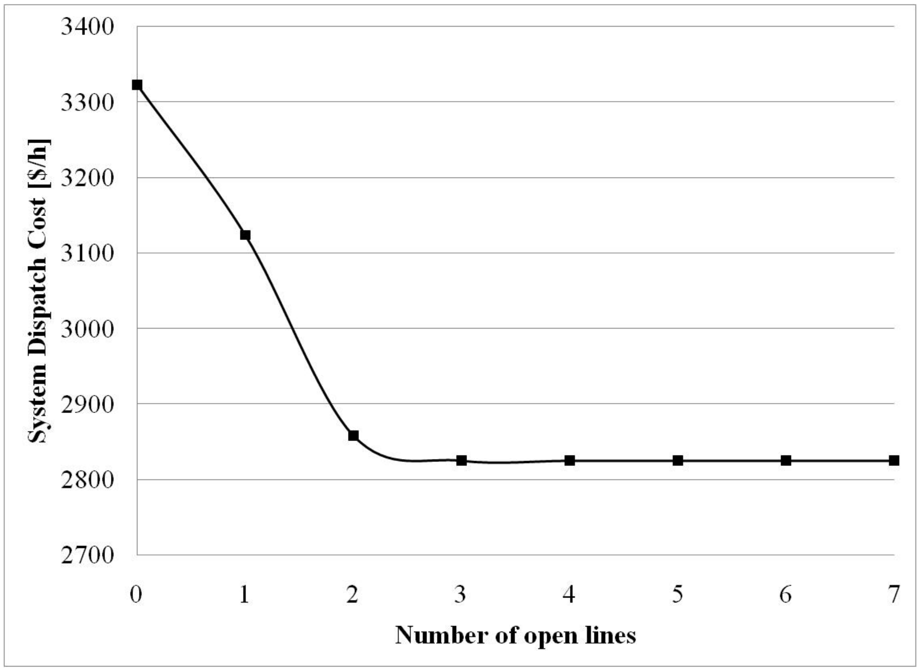

Figure 5. System Dispatch Cost, IEEE 118-bus model with N-1 contingencies

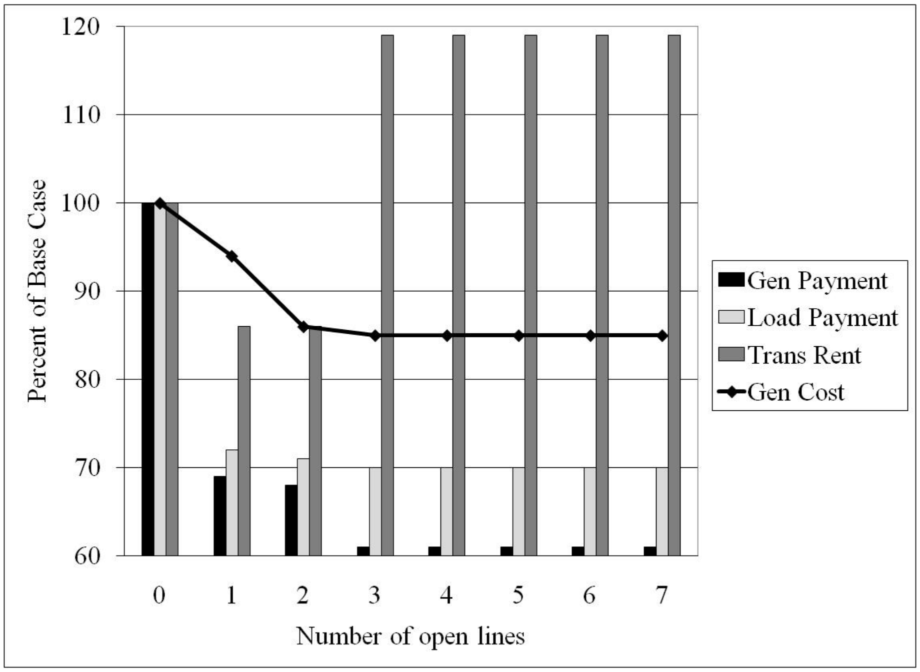

Figure 6. Total System Payments, IEEE 118-bus model with N-1 contingencies

The savings achieved after introducing the N-1 contingency constraints decreased the percent savings realized as compared to the switching dispatch with no contingency. An analysis of a different network model, the IEEE 73 Reliability test case, demonstrated a contrasting result. The original dispatch with switching with no contingencies resulted in almost no cost savings. However, including N-1 contingency constraints produced a cost reduction of 8%. This is presumably because when the network is more constrained (as it is when it must comply with contingency constraints) there is more opportunity for savings.[15]

6. Analysis of ISO Network

We now turn our attention to testing the optimal transmission switching problem on a model of an actual modern network: the New England Independent System Operator (ISO-NE). Characteristics of this model are summarized below. A more detailed discussion of this model can be found in Hedman et al. (2008c).

System Dispatch Cost

The model dispatch was first solved without transmission switching; the optimal dispatch cost was $474k/h. The OPF with transmission switching was then run for j=1, …,10, with the generalized upper bound constraint as an equality rather than an inequality to improve the solution process. The best found solution using this technique was $427k/h, or 9% savings. We also used a heuristic referred to as "intelligent learning" to obtain a 13% savings, or total generator cost of $412k/h. This heuristic consists of identifying a small sub-set of the total set of transmission elements that are good candidates for switching (e.g. they provided large savings in the past or under other loading scenarios). These lines are then considered for switching; all other transmission lines are fixed closed.

System Prices

Once again, it is informative to examine the changes in nodal prices and the impact they have on total payments. In **Error! Reference source not found.**, the percent changes in total generator cost, generator revenue, load payments and transmission costs from the no-switching case are

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[15] This case is described in detail in Hedman et al. (2008b).

shown. These total values are different for each transmission topology, but they are all less than the original, no-switching case.

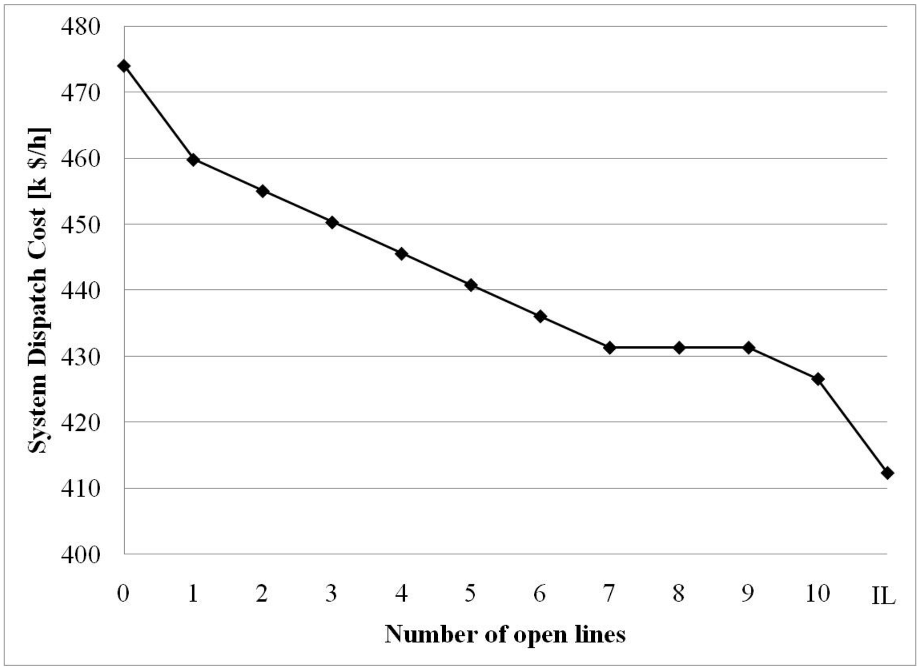

Figure 7. System Dispatch Cost, ISO-NE model

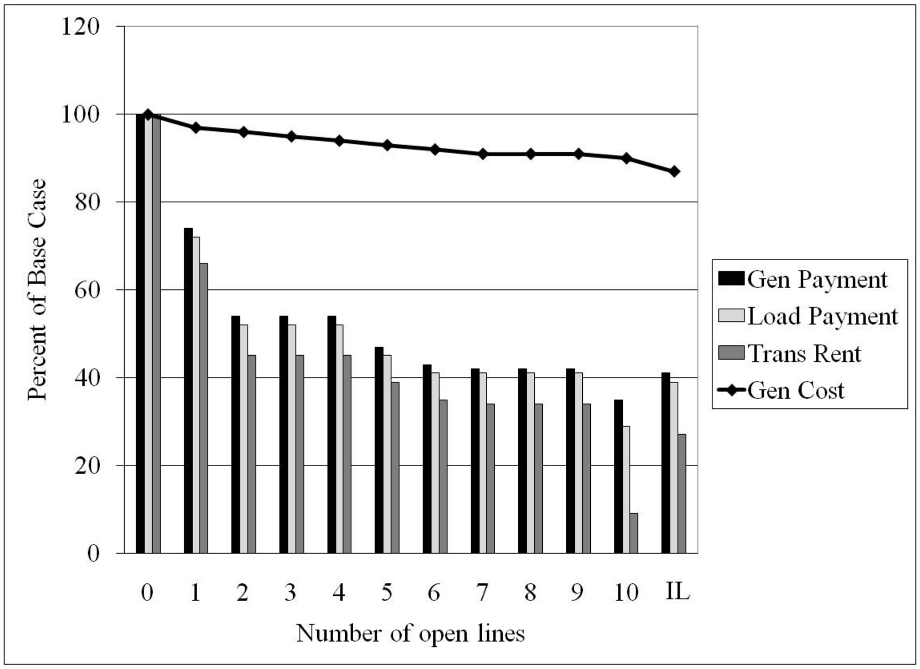

Figure 8. Total System Payments, ISO-NE

It is interesting to note that we also solved the optimal transmission switching problem for a 200-bus equivalent model of the California ISO.[16] This model makes many simplifications from the actual network; for instance, in actuality California contains thousands of buses, not 200. Allowing for transmission switching in this model resulted in negligible savings. There are two reasons for this. First, thermal limits were not provided, and thus not enforced, for over half of the lines. Second, and more importantly, this is an equivalence system, where parallel lines are collapsed into a single representative line and other simplifications are made. This eliminates much of the relevant information for making transmission switching decisions to improve economic dispatch. In some cases, opening a parallel line can improve the dispatch, but this is not possible if the lines have been modeled as a single equivalent line. The benefits of optimal transmission switching can only be realized fully on models that are detailed in their representation of the transmission grid.

7. Policy Implications

Optimal transmission switching has been shown to have the potential for improving the economic efficiency of network dispatch. However, there are several practical issues to resolve and policy issues to examine before optimal transmission switching can be implemented in real systems. These include computational issues, ensuring reliability, equipment investments and financial considerations.

Computational Issues

The main computational hurdle to overcome is decreasing solution time. The scale of real-world networks is large, and, as seen in the section above describing the ISO-NE results, large MIPs take a long time to solve. If transmission switching is going to be determined in the day-ahead time frame, market operators will only have a few hours to find a solution. Even though the preliminary studies presented here had solution times much longer than this, current efforts to

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[16] See Hedman et al. (2008c) for more details.

improve solution time is promising. We are currently working to tune solver parameters, identify unique problem structures, and develop solution heuristics, all with promising results.

At the same time, solver software is continually improving (Bixby, 2002). The solver used here, CPLEX, has been continually improving over the last 10 to 15 years. A generator unit commitment problem run on one computer remained unsolved after 8000 seconds using a version of the CPLEX solver from 1998, while the same problem on the same computer using the 2008 version of CPLEX solved to optimality in just over 100 seconds.[17] General improvements in computing power and techniques, such as grid computation, will also aid in solving these large network problems (Bussieck, Ferris, & Meeraus, 2007).

Reliability

Maintaining reliability remains a primary goal in network dispatch. Switching lines in and out must be done in a way that is compatible with system security. Current practice in many control areas includes line switching, which indicates that this is not only possible but prosaic. Using a contingency formulation, like the one presented in this paper, is one way of ensuring transmission switching is being performed in a way that maintains system security. The N-1 contingency formulation can ensure steady-state reliability, but the dynamic security implications of switching transmission lines should also be examined.

Equipment Investment

To implement optimal transmission switching, both software and hardware investments would be necessary. ISOs or grid operators would need to update the dispatch optimization problem to include switching. Also, communication and automated switching equipment must be installed and confirmed to be reliable, so lines can be opened and closed quickly and with full knowledge of the system conditions. Automated switching is a mature technology, thus implementing optimal switching would be a matter of investing in available technologies and training operators and technicians, not developing new technologies. Physical limits on equipment, such as how often or how quickly lines can be switched in and out, can be easily added to the optimization formulation

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[17] Personal communication with Professors Robert Bixby and William Stewart.

as constraints. Given the potentially large cost savings identified here this capital and personnel outlay for this ‘smart grid’ technology may very well be justified, and is an empirical calculation.

Financial Considerations

As described above in the discussion on nodal pricing and changes in total payments, use of optimal transmission switching in a market setting can result in big variations in prices charged to customers and payments made to generators. Because of this, it is extremely important that market participants have an opportunity to hedge their financial positions in a forward market. If positions are hedged, a market participant is indifferent to the short-term prices in the market; they can take advantage of them if they would improve profits or costs, and if not they can abide by their forward positions.

The transmission system is typically funded by regulated rates, even in areas that have opened generation to competition. Thus switching lines in and out does not have the same financial implications as committing or de-committing generators owned by private companies, because transmission lines, unlike generators, are not paid for hours operated or power transferred. The switching decisions, however, would need to be made by impartial organizations having no interest in the financial effects of changing the system topology. For instance, a vertically-integrated utility with control over switching lines may be able to modify the network to favor their own generators or discriminate against competitors. This would be a situation to guard against.

Financial transmission rights (FTRs) need to be analyzed in a non-static network. Revenue adequacy for transmission rights is not a unique problem to transmission switching. Insufficiently funded transmission rights have been found to occur when transmission lines experience planned or forced outages, when new transmission lines are built, even when the model used to calculate the rights uses DC approximations (Hogan, 2002) (Kristiansen & Rosellón, 2006) (Lesieutre & Hiskens, 2005) (Liu & Gross, 2004). The introduction of optimal switching may affect some aspects of this issue, but not the essence of the problem. Appropriate handling of FTRs, as well as other financial and market issues, need further study before optimal switching could be implemented. The bottom line is that optimal switching can improve (and in any case will not reduce) the amount of surplus in the market. Therefore, inadequately funded rights can be made whole by redistributing the surplus in a way that benefits all market participants (or at least does no harm).

Before implementation, it is also necessary to determine whether the benefits of implementing optimal transmission switching would outweigh the costs. There are potentially many costs, including investing in or upgrading switching and communications equipment, developing computer software, and training personnel. While this study is not meant to be a formal cost/benefit analysis, we conclude that the potential benefits are promising enough to warrant further study of this optimal transmission switching.

8. Conclusion

As we consider the future of the transmission system, novel technologies and large investments in physical assets, it is important to consider solutions that are low-cost and require minimal investments and new infrastructure. Optimal transmission switching has been shown to improve the economic dispatch on systems, from small test examples to large ISO models. Analysis included varying load profiles, dispatching that ensures survival of contingencies, and switching on an ISO network. The improvements realized here are substantial enough to consider optimal transmission switching a promising method worthy of further examination.

APPENDIX: Nomenclature

Indices

$n = 1,\ldots, N$: nodes

$k = 1,\ldots, K$: lines

$g = 1,\ldots, G$: generators

$d = 1,\ldots, D$: loads

j: number of lines allowed to open in the generalized upper bound constraint

c: $N1_{gc}$ or $N1_{kc}$ contingency

Variables

θ_{n}: voltage angle at node n

θ_{nc}: voltage angle at node n for contingency c

P_{nk}, P_{ng}, P_{nd}: real power flow to or from line k, generator g, or load d to node n.

$P_{nkc}, P_{ngc},$: real power flow to or from line k or generator g to node n for contingency c.

z_k: binary variable indicating whether transmission line k is removed from the system (open, $z_k = 0$), or in the system (closed, $z_k = 1$)

TC: Total system dispatch cost

Parameters

P_{nk}^{max}, P_{nk}^{min}: maximum and minimum capacity of line k

$P_{kc}^{min}, P_{kc}^{max}$: max and min transmission element k emergency rating

P_{ng}^{max}, P_{ng}^{min}: maximum and minimum capacity of generator g

θ_n^{max}, θ_n^{min}: maximum and minimum voltage angle at node n

c_{ng}: cost of generating electricity from generator g located at node n

B_k: electrical susceptance of line k

M_k: large number, tailored to each constraint

$N1_{gc}$, $N1_{kc}$: binary parameter that is 0 when the element is the contingency and 1 otherwise

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