International Journal of Integrated Engineering, Vol. 8 No. 1 (2016) p. 25-34

Coordinated Generation and Transmission Maintenance Scheduling Considering Network Constraints via GGDF and ODF

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Abstract: This paper proposes a coordinated generation and transmission maintenance scheduling by incorporating network constraints. The main advantage of the proposed approach is that maintenance is scheduled at the optimal period of the lowest possible operating cost while satisfying all the specified constraints. In this approach, sensitivity factors (GGDFs and ODFs) which are based on DC approximation are applied to calculate the line flows in normal and maintenance conditions. They are applied due to their simplicity, linearity, physical comprehension and rapidity of computation. To simulate the effect of network constraint on maintenance schedule and operating cost, several cases are studied with and without transmission limit constraints. To ensure the accuracy of these sensitivity factors, power flows on each line are compared with the one obtained from a PSSE simulator. The result shows that generators and transmission lines are scheduled at periods that satisfy the transmission capacity limit.

Keywords: Coordinated generation and transmission maintenance scheduling, GGDFs, MILP, ODFs, SCUC.

1. Introduction

Maintenance is one of the major activities for electric utilities. In general, maintenance can be divided into two categories; breakdown maintenance and preventive maintenance. Breakdown maintenance is performed when a sudden equipment failure occurs, which requires a maintenance crew to execute some repair work. This is categorized as unscheduled maintenance which is done only if a breakdown occurs in the system. Meanwhile, preventive maintenance is a periodic inspection procedure done upon parts of the equipment to lessen the likelihood of them failing. It is performed on the existing on-line equipment that has to be shut down temporarily for maintenance tasks. By regular inspection, the equipment's life span can be extended, reduce force outage rate, keep efficiency at reasonable level, and ensure system reliability[1].

Incorporating transmission network security constraints into the maintenance scheduling problem is essential, which could precisely evaluate the impacts of generation and transmission maintenance scheduling on the power flows through transmission lines [2]. Due to physical limitations, transmission lines should not be utilized beyond their maximum capacity for an extended period [3]. Thus, incorporating transmission network constraints into the maintenance scheduling problem would guarantee that power transfer will not exceed the physical limits of transmission lines. Transmission line capacity limits can be expressed in MW or MVA. MW loading limits are considered in this paper.

As far as the network is concerned, the transmission system needs to be appropriately modeled in the maintenance problem. It can be modeled either using a simplified representation of network flows, DC optimal power flow or by employing a full set of optimal AC nonlinear power equations. DC power flow is a simplification of full power flow looking only at active power flows, neglecting voltage support, reactive power management and transmission losses. Due to its simplicity and robustness, it has been widely used by the previous work. Most of them incorporated the DC power flow equation in the maintenance scheduling problem based on Kirchhoff's Law [4-8]. It is noted that, the use of sensitivity factors in evaluating the transmission network security as well as in analyzing the impact on an individual maintenance line has never been addressed in previous maintenance work. Specifically, ODFs are usually used to perform contingency analysis in a power system.

However, a different approach is used in this research work by using sensitivity factors (GGDF and ODF), in which DC approximation is still adopted. In this

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method, power flow is calculated based on the power generation of each unit. If one or more transmission lines are outaged for maintenance, the power flow on the remaining transmission lines may change accordingly by means of the ODF value. By using these factors, the power flow of each line can be calculated easily at each time interval without requiring additional power flow simulation [9-10].

In normal conditions, line flow is computed through sensitivity factors called GGDFs. These factors represent the portion of generation supplied by each generator contributing to the power flow of a monitored transmission line. In other cases, ODFs are adopted when one or multiple line outages are involved. Here, the line outage is referring to the line under maintenance. Generally, the line maintenance would cause the changes in other line flows. In this sense, ODF measures how a change in a line's status affects the flow in other lines in the system.

The remaining of the paper is organized as follows. In section 2, the proposed co-optimization model is presented. In section 3 problem formulations is elaborated. Meanwhile, in section 4, numerical case studies on the benchmark of six-bus system and IEEE118-bus system are discussed in detail. Finally, the conclusions are given in section 5.

2. Solution procedure

In this paper, maintenance of generators and transmission lines are optimal scheduled at the lowest possible total maintenance and operating cost. Thus, unit commitment and generation/transmission maintenance schedule need to be optimized simultaneously. Fig. 1 shows the flowchart of the proposed approach. In this study, all the three sub-problems are optimized simultaneously by the CPLEX optimizer, which adopts the branch-and-bound-and-cut (BB&C) approach. The basic concept underlying the branch-and-bound technique is to divide and conquer, which involves three steps including branching, bounding, and fathoming [11]. The branching process starts by partitioning the entire set of feasible solutions into smaller subsets known as nodes. A node is fathomed if the solution of the node sub-problem is infeasible, the value of the objective function at the node is worse than the cut-off value for branch-and-cut, or the linear programming relaxation at the node provides an integer solution.

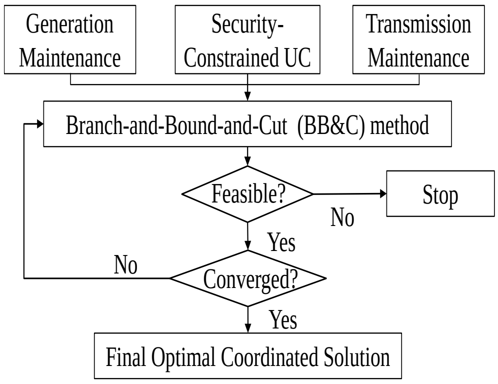


Fig. 1 Flowchart of the proposed solution procedure

CPLEX achieves the final optimal solution when certain stopping criterion is met. The relative MILP gap tolerance (1) is used in this paper, which calculates the relative difference between the best integer objective and the objective of the best node remaining. The threshold of the relative MILP gap is set as 1x10-4. That is, the BB&C procedure stops when an integer feasible solution is proven to be within 0.01% optimality.

$$Gap = \frac{|\, BestNode - BestInteger \,|}{1^{-10} + |\, BestInteger \,|} \tag{1}$$

3. MILP Formulation

The proposed coordinated generation and transmission maintenance scheduling model addresses economic and reliability aspects simultaneously, in which the maintenance schedule is determined for minimizing on the total maintenance and operation costs of the entire system while ensuring system security. Thus, the maintenance is usually scheduled at times when the operating cost is relatively, while system reliability is ensured via multiple security constraints. This paper includes the formulation for thermal unit while other types of generators such as hydro, nuclear, and wind units can be incorporated with minor modification. The detailed model is presented as follows.

3.1 Objective Function

The objective function (2) is to minimize the total maintenance and operation costs of the entire system. The first and second part of the objective function is referred to the maintenance cost of the units and lines, respectively, while the third part represents the production cost of the unit. In this approach, quadratic production cost function of each unit was approximated by a set of piecewise blocks in which its detail formulation can be referred in [12-13]. Meanwhile, the maintenance cost is assumed fixed throughout interval.

$$min \sum_{j=1}^{J} \sum_{t=1}^{T} \left\{ C_{m,jt} \bullet X_{jt} + C_{m,lt} \bullet X_{lt} + C_{g,jt} \bullet p_{j,t} \bullet I_{jt} \right\} \tag{2}$$

3.2 Prevailing Constraints

To accurately formulate actual operation characteristics of power systems, the proposed model includes short-term SCUC constraints, transmission line limit constraints, and maintenance constraints. The inclusion of these constraints would ensure that generator and transmission line maintenance is scheduled according to their pre-specified windows and durations, while in consistence with unit commitment schedules and power flow limits.

a) Generation limit constraints: Each generator should be operated between its rated minimum and maximum power capacities, P_{min} and P_{max}, respectively as stated in (3). I_j indicates the commitment status of unit *j*.

$$P_{min,j} \bullet I_{jt} \le p_{j,t} \le P_{max,j} \bullet I_{jt} \quad (3)$$

b) Power balance constraints: In actual operation, the total power production in each period must fulfill the required load demand as stated in (4). p_j is the output power of unit *j*, while $D(t)$ is the load demand at period *t*.

$$\sum_{j=1}^{NG} p_{j,t} = D_t \quad (4)$$

c) Minimum up and down time constraints: Due to physical characteristics, a thermal unit cannot be re-synchronized and desynchronized immediately, as it must fulfill the required minimum up, T_j^{on} and down times, T_j^{off} that are pre-specified by manufacturers. Minimum up-time refers to the time period that a unit needs to be in the ON state before it can be shut down, while minimum down-time refers to the time period required to be OFF before it can be operated again. Mathematical expressions for minimum-up and minimum-down time constraints are described in (5)-(7) and (8)-(10), respectively. Constraints (5) and (8) are designed to consider a generator's initial state that is defined by q_{j0}^{on} and q_{j0}^{off}.Constraints (6) and (9) are used for satisfying required minimum-up and down times in subsequent hours, respectively. Constraint (7) is used to ensure that if unit j starts up in the final periods, it would remain online until the end of the time horizon. Likewise, constraint (10) ensures unit j remains offline when it is shut down in the final periods.

$$\sum_{t=1}^{UT_j} \left(1 - I_{jt}\right) = 0 \quad (5)$$

Where,

$$UT_j = max\left\{0, \min\left[NT, \left(T_j^{on} - q_{j0}^{on}\right) \bullet I_{jo}\right]\right\}$$

$$\sum_{\tau=t}^{t+T_j^{on}-1} I_{j\tau} \ge T_j^{on} \bullet \left(I_{jt} - I_{j(t-1)}\right)$$

$$\forall t = UT_j + 1, \ldots., NT - T_j^{on} + 1 \quad (6)$$

$$\sum_{\tau=t}^{NT} I_{j\tau} - \left(I_{jt} - I_{j(t-1)}\right) \ge 0$$

$$\forall t = NT - T_j^{on} + 2, \ldots., NT \quad (7)$$

$$\sum_{t=1}^{DT_j} I_{jt} = 0 \quad (8)$$

Where,

$$DT_j = max\left\{0, \min\left[NT, \left(T_j^{off} - q_{j0}^{off}\right) \bullet \left(1 - I_{j0}\right)\right]\right\}$$

$$\sum_{\tau=t}^{t+T_j^{off}-1} \left(1 - I_{j\tau}\right) \ge T_j^{off} \bullet \left(I_{j(t-1)} - I_{jt}\right)$$

$$\forall t = DT_j + 1, \ldots., NT - T_j^{off} + 1 \quad (9)$$

$$\sum_{\tau=t}^{NT} 1 - I_{j\tau} - \left(I_{j(t-1)} - I_{jt}\right) \ge 0$$

$$\forall t = NT - T_j^{off} + 2, \ldots.., NT \quad (10)$$

d) Ramp rates constraints: The rates of loading and unloading of a unit in two successive periods should be within the ramping up, RU and ramping down, RD limits as illustrated in (11)-(12). These constraints indicate that in the transition state from 0 (off) to 1 (on) or vice versa, a generator should increase/decrease according to start up, UP and shut-down, DP ramp limits.

$$p_{j,t} - p_{j,(t-1)} \le RU_j\left(I_{j(t-1)}\right) + UP_j\left(I_{jt} - I_{j(t-1)}\right) + P_{j,max}\left(1 - I_{j,t}\right) \quad (11)$$

$$p_{j,(t-1)} - p_{j,t} \le RD_j\left(I_{jt}\right) + DP_j\left(I_{j(t-1)} - I_{jt}\right) + P_{j,max}\left(1 - I_{j(t-1)}\right) \quad (12)$$

e) Spinning and non-spinning reserves are two types of system operating reserve. Spinning reserve, SR is the online reserve capacity provided by generators that are already connected to the power system and ready to meet the electric demand within ten minutes of a dispatch instruction by system operator. The spinning reserve constraints are represented by (13)-(15). In contrast, non-spinning reserve is the offline generation capacity that can be ramped to capacity as denoted by QSC . The non-spinning reserve constraints are formulated in (16) and (17). The operating reserve, OR should be adequate to cater for any loss in generating capacities due to forced outages or planned maintenance to ensure system security.

$$\sum_{j=1}^{NG} SR_{jt} \ge R_{st} \quad (13)$$

$$\sum_{j=1}^{NG} OR_{jt} \geq R_{ot} \tag{14}$$

$$SR_{jt} \leq P_{\max,j} \bullet I_{jt} - p_{jt} \tag{15}$$

$$SR_{jt} \leq 10 \bullet MSR_{j} \bullet I_{jt} \tag{16}$$

$$OR_{jt} = SR_{jt} + (1 - I_{jt}) \bullet QSC_{j} \tag{17}$$

f) Coupling constraints: The proposed optimization model has scheduled maintenance and unit commitment simultaneously; hence coupling constraints must be included in the formulation to ensure that unit status (I)/line status (J) and unit maintenance status (X) /line maintenance status (Y) are contradicted to each other. In other words, unit/line cannot be operated when it is scheduled for maintenance. Mathematical expression of the coupling constraints for units and lines are stated in (18) and (19), respectively.

$$X_{jt} + I_{jt} \leq 1 \tag{18}$$

$$Y_{lt} + J_{lt} \leq 1 \tag{19}$$

g) Maintenance duration constraints: The maintenance requires a certain time period for guaranteeing the proper completion of the maintenance task which is denoted by MD. Generators and transmission lines are scheduled for maintenance during its maintenance window, which is defined by the interval between its starting period, PS and ending period, PE. Generator and line maintenance duration is mathematically expressed as (20) and (21), respectively.

$$\sum_{t=PS_j}^{PE_j} X_{jt} = MD_j \tag{20}$$

$$\sum_{t=PS_l}^{PE_l} Y_{lt} = MD_l \tag{21}$$

h) Maintenance continuity constraints: Constraint (22) indicates that once maintenance is started, it must be finished according to its specified duration. Besides, the constraint ensures that maintenance is scheduled within specified maintenance window.

$$\sum_{t=k}^{k+MD_j-1} X_{jt} \geq MD_j \bullet \left[X_{jk} - X_{j(k-1)}\right],$$
$$\forall j, k = PS_j, \ldots\ldots, PE_j - MD_j + 1$$
$$\sum_{t=k}^{PE_j} \left\{X_{jt} - \left[X_{jk} - X_{j(k-1)}\right]\right\} \geq 0,$$
$$\forall j, k = PE_j - MD_j + 2, \ldots\ldots, PE_j \tag{22}$$

i) Crew constraints: The availability of manpower that can perform the maintenance is limited in each time period. Thus, to represent the limited crew availability, certain generators cannot be maintained at the same time. For instance, (23) indicates that units 1, 2, and 3 cannot be maintained simultaneously.

$$X_{1t} + X_{2t} + X_{3t} \leq 1 \tag{23}$$

j) Transmission flow limits: Power systems should be operated such that the power flow in a transmission line does not exceed the maximum available power transfer capability (24). In this paper, the line flow is calculated via the sensitivity factor GGDFs. (25) shows that power flow is calculated by multiplying $D_{l,j}$, the GGDFs of generator j with respect to line l, with $p_{j,t}$, the power production for generator j. GGDFs is calculated using the base case power flow results PF_l^0, power production p_j, and GSDFs $A_{l,j}$ as described in (26)-(27). $D_{l,r}$ denotes GGDFs of line l due to one MW injection at the reference bus. GSDFs is calculated based on the reactance matrix and the DC approximation as shown in (28), where m and k are referred to the initial and the terminal buses of line l, respectively. Table 1 shows the example of GGDF table of a system with three generators and three lines, while (29)-(31) are the examples of power flow calculations with respect to the formula stated in (25).

$$-PF_l^{\max} \leq PF_l \leq PF_l^{\max} \tag{24}$$

$$PF_{l,t} = \sum_{j=1}^{NG} D_{l,j}\; p_{j,t} \quad l = 1, \ldots, NL \tag{25}$$

$$D_{l,j} = D_{l.r} + A_{l,j} \tag{26}$$

$$D_{l,r} = \frac{PF_l^0 - \sum_j^{NG} A_{l,j}\; p_j}{\sum_i^{NG} p_i}, \; for\; j \neq r \tag{27}$$

$$A_{l,j} = \frac{x_{mi} - x_{ki}}{x_l}, l = 1, \ldots\ldots, NL \tag{28}$$

Table 1. Example GGDF Table

Equipment	G1	G2	G3
L1	$D_{1,1}$	$D_{1,2}$	$D_{1,3}$
L2	$D_{2,1}$	$D_{2,2}$	$D_{2,3}$
L3	$D_{3,1}$	$D_{3,2}$	$D_{3,3}$

$$PF_{L1,t} = D_{1,1}\; p_{1,t} + D_{1,2}\; p_{2,t} + D_{1,3}\; p_{3,t} \tag{29}$$

$$PF_{L2,t} = D_{2,1}\; p_{1,t} + D_{2,2}\; p_{2,t} + D_{2,3}\; p_{3,t} \tag{30}$$

$$PF_{L3,t} = D_{3,1}\; p_{1,t} + D_{3,2}\; p_{2,t} + D_{3,3}\; p_{3,t} \tag{31}$$

k) Transmission flow considering maintenance condition: ODFs are adopted when one or multiple line outages are involved. Here, the line outage is referring to the line under maintenance. In this sense, ODFs measures how a change in line's status affects the flow in other lines in the system. (32) shows a general formulation of a new power flow of the line when line maintenance is taking into consideration. Here, $d_{l,f}$ represents the value of ODFs for line l with respect to the maintenance line *f*. This value shows the percentage of incremental real power flow on monitored transmission line caused by line maintenance. (33) points out on how ODF is obtained through DC approximation.

To evaluate the impact of individual maintenance line, (32) is modified to (34) in which line maintenance status is included in the formulation. However, this equation becomes a non-linear form as it involved the multiplication of a continuous variable (i.e., output power) and a binary variable (i.e., line maintenance status). In order to transform the non-linear constraints to linear one, constraints (35) has been added in the formulation, where $p'_{j,t}$ is equal to the output power $p_{j,t}$ when the line is under maintenance, otherwise it is 0. Tables 2 shows the example of ODF tables, while (36)-(38) present line flow calculations with respect to (34), in which L3 is chose to be under maintenance.

$$PF_{l,t}^{new} = PF_{l,t} + d_{l,f} PF_{f,t} \tag{32}$$

$$d_{l,f} = \frac{\bar{x}_f (x_{ms} - x_{ks} - x_{me} + x_{ke})}{\bar{x}_l - (x_{ss} - x_{ee} - 2x_{se})} \tag{33}$$

$$PF_{l,t}^{new} = PF_{l,t} + \sum_{f=1}^{NF} Y_{ft} \bullet d_{l,f}\ PF_{f,t} \tag{34}$$

$$p_j + p_{\max,j}(Y_l - 1) \le p'_j \le p_{\max,j}(Y_l) \tag{35}$$

Table 2. Example ODF Table

Line	L1	L2	L3
L1	0	$d_{1,2}$	$d_{1,3}$
L2	$d_{2,1}$	0	$d_{2,3}$
L3	$d_{3,1}$	$d_{3,2}$	0

$$PF_{L1,t} = [D_{1,1}\ p_{1,t} + D_{1,2}\ p_{2,t} + D_{1,3}\ p_{3,t}] + (d_{1,3})(X_3)[D_{3,1}\ p'_{1,t} + D_{3,2}\ p'_{2,t} + D_{3,3}\ p'_{3,t}] \tag{36}$$

$$PF_{L2,t} = [D_{2,1}\ p_{1,t} + D_{2,2}\ p_{2,t} + D_{2,3}\ p_{3,t}] + (d_{2,3})(X_3)[D_{3,1}\ p'_{1,t} + D_{3,2}\ p'_{2,t} + D_{3,3}\ p'_{3,t}] \tag{37}$$

$$PF_{L3,t} = [D_{3,1}\ p_{1,t} + D_{3,2}\ p_{2,t} + D_{3,3}\ p_{3,t}] + (d_{3,3})(X_3)[D_{3,1}\ p'_{1,t} + D_{3,2}\ p'_{2,t} + D_{3,3}\ p'_{3,t}] = 0 \tag{38}$$

4. Results and Discussion

To evaluate the effectiveness of the proposed approach, several cases on a six-bus system and the IEEE 118-bus system are studied comprehensively. The duration considered in the case studies is one week with hourly time resolution. The system spinning reserve requirement is set as 5% of the total load.

a) Six-Bus System

The six-bus system consists of three generators, seven transmission lines, and three load demands. Tables 3-5 show generator information, maintenance data, and transmission network data, respectively. All three generators have already been in the ON state for a couple of hours, as specified in the last column of Table 4. Maintenance windows specified in Table 5 are from long-term study and in this short-term planning, specific maintenance hour will be determined. In addition, all the three generators could not be on maintenance outage simultaneously. Fig. 2 shows the system load profile, in which the peak load is 270 MW. Table 7 and 8 show the GGDF and ODF value obtained for this system, The following six cases are evaluated to demonstrate the proposed model:

Case 0A) Unit commitment without transmission limit constraint (base case).
Case 0B) Unit commitment with transmission limit constraint (base case).
Case 1A) Unit commitment and generation maintenance scheduling without transmission limit constraint.
Case 1B) Unit commitment and generation maintenance scheduling with transmission limit constraint.
Case 2A) Unit commitment and transmission maintenance scheduling without transmission limit constraint.
Case 2B) Unit commitment and transmission maintenance scheduling with transmission limit constraint.
Case 3A) Unit commitment, and generation and transmission maintenance scheduling without transmission limit constraint.
Case 3B) Unit commitment, and generation and transmission maintenance scheduling with transmission limit constraint.

Table 3: Generator Cost Data

Unit	a (MBtu/h)	b (MBtu/MWh)	c (MBtu/MW^{2}h)
G1	176.9	13.5	0.00045
G2	129.9	32.6	0.001
G3	137.4	17.6	0.005

Table 4: Operating Data

Unit	Pmin (MW)	Pmax (MW)	Ramp Rate (MW/h)	Min-up Time (h)	Min-down Time (h)	Initial State
G1	100	220	55	4	4	4
G2	50	150	50	2	3	2
G3	20	100	40	1	1	1

Table 5: Maintenance Data

Equipment	Maintenance Cost ($/h)	Maintenance Window	Outage Duration (h)
G1	84	1 - 168	10
G2	125	1 - 168	10
G3	167	1 - 168	10
L2-3	2080	1 - 168	24

Table 6: Transmission Line and Transformer Data

Line	From Bus	To Bus	X (pu)	Line Limit (MW)
L1-2	1	2	0.170	200
L1-4	1	4	0.258	200
L2-3	2	3	0.037	100
L2-4	2	4	0.197	80
L3-6	3	6	0.018	100
L4-5	4	5	0.037	100
L5-6	5	6	0.140	100

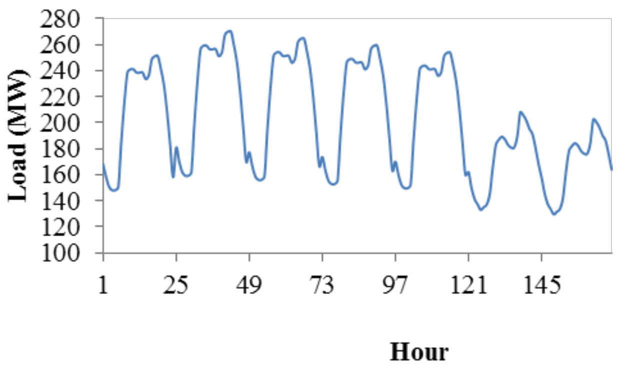


Fig. 2. Load profile over 168 hours of the planning horizon

Table 7: GGDF value of each generator respected to each line

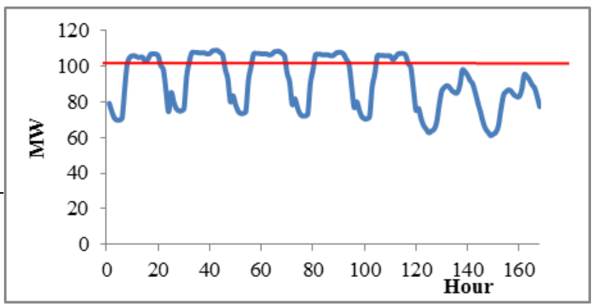
Line/gen	G1	G2	G3
L1-2	0.528877	-0.15309	-0.10584
L2-3	0.471123	0.15309	0.105841
L1-4	0.368198	0.514241	-0.33586
L2-4	0.160673	0.332663	0.23001
L4-5	0.168201	0.314244	-0.53585
L5-6	0.231797	0.085754	-0.06415
L3-6	-0.1682	-0.31424	-0.46414

Table 8: ODF value of each maintenance line respected to each line

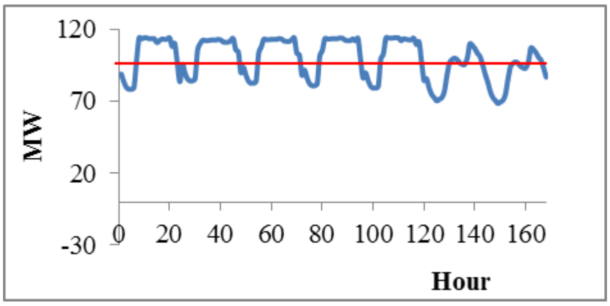
Line	L1-2	L2-3	L1-4	L2-4	L4-5	L5-6	L3-6
L1-2	0	1	0	0	0	0.32	0.32
L2-3	1	0	0.32	0.35	0.32	0	0
L1-4	0	0.46	0	0	0.65	1	1
L2-4	0	0.54	0.68	0.68	0	0	0
L4-5	0	0.46	0	0	0.65	1	1
L5-6	0.46	0	1	1	0	0	0
L3-6	0.46	0	1	1	0	0	0

Cases 0 to 3 exhibit the effect of transmission line limits on unit commitment, maintenance scheduling, and operating cost. Case 0 run as a base case where only unit commitment and economic dispatch are obtained. It is noted that, at the initial stage of this evaluation, which is Case 1 and 2, generation maintenance scheduling and transmission maintenance scheduling are solved individually. Then, in the next case which is Case 3, the proposed model is demonstrated by co-optimizing of unit commitment, and generation and transmission maintenance scheduling. Below are the findings summarized for all cases.

Case 0A).In this case, unit commitment is solved without considering any equipment maintenance. Unit commitment results can be referred in Table 11. As to minimize the operating cost, the cheapest unit G1 is committed over the entire week to supply the load. Due to the capacity limit of G1, the second cheapest unit G3 is committed at times when G1 could not support the load by its own. Meanwhile, the most expensive unit G2 is always OFF. The total operating cost is $510,543.18. As the transmission limit is not considered in this case, this schedule would result in violation on L1-2 and L1-4. Fig.3 shows the power flow on these lines over the planning horizon, where it shows that the power flow higher than 100MW occurred on certain hours. The rest of the lines are under their capacity limit. As stated earlier, the proposed model has adopted sensitivity factors for lines flow calculation. To verify the accuracy of these calculations, the power flow simulation is performed at hour 18 by using PSSE simulator. The comparison result in Table 9 shows that the power flow on each line obtained using sensitivity factors mostly the same as obtained using PSSE simulator. Besides, from the simulation, it is clear that during hour 18, the power flow on L1-2 and L1-4 are overloaded, as highlighted in red in Fig.4.



(a) L1-2



(b) L1-4
Fig. 3 Power flow on the selected line over the planning horizon in Case 0A

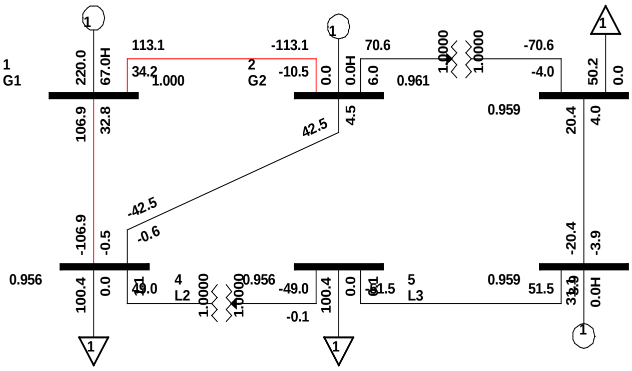
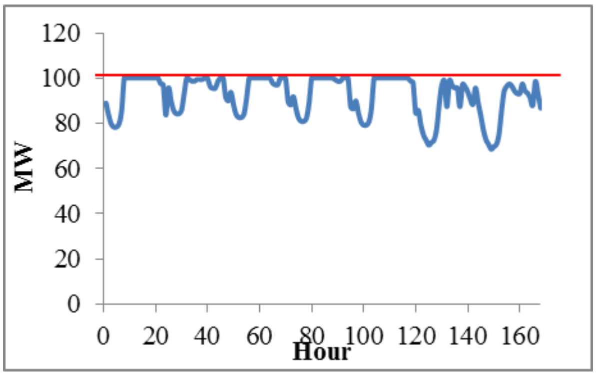


Fig.4 Power flow simulation at hour 18 from PSSE for Case 0A

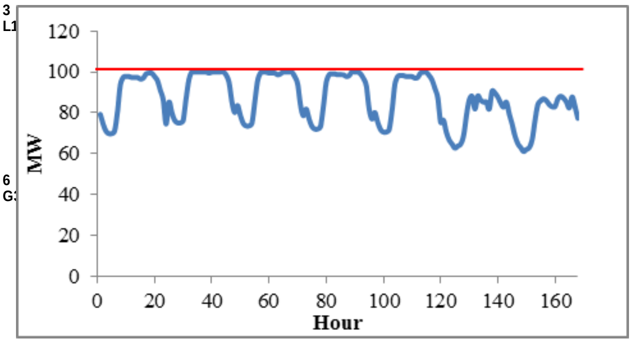
Table 9: Comparison of power flow between sensitivity factors and PSSE simulator at hour 18 for Case 0A

Line	Power flow using sensitivity factors (MW)	Power flow from PSSE simulator (MW)
L1-2	113.0612	113.1
L1-4	106.9388	106.9
L2-3	70.5585	70.6
L2-4	42.50143	42.5
L3-6	20.33908	20.4
L4-5	49.00026	49
L5-6	51.438	51.5

Case 0B) In this case, the changes in unit commitment schedule due to transmission limits can be clearly observed in Table 11. From the result, unit commitment of G1 and G2 are the same as compared to Case 0A, and the only different is the schedule of G3. Here, G3 is committed more for satisfying line limit constraints. As a consequence, the operating cost is increased to $521 707. This schedule does not cause violation on any line. The new power flow for L1-2 and L1-4 is illustrated in Fig.5 which shows that the flow on these lines is under their capacity limits. The power flow at hour 18 is also performed using PSSE simulation and its result is depicted in Fig.6. Note that the power flow on L1-2 and L1-4 has been reduced to 100MW and 99.4MW, respectively. Table 10 shows the comparison of power flow of all lines that obtained from sensitivity factors and PSSE simulator. It can be concluded that the power flow calculated in the proposed model mostly the same as simulated using PSSE simulator.



(a)L1-2



(b)L1-4
Fig. 5 Power flow on the selected line over the planning horizon in Case 0B

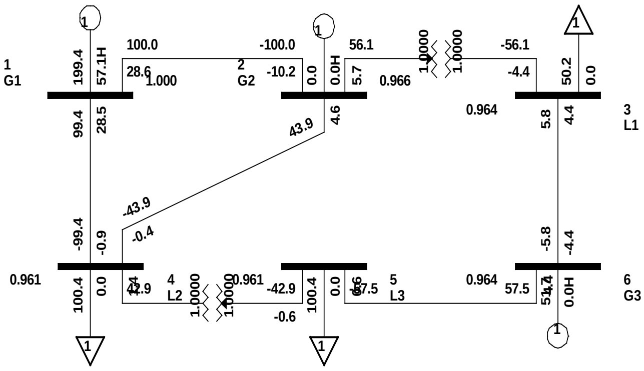


Fig.6 Power flow simulation at hour 18 from PSSE for Case 0B

Table 11: Unit commitment schedule for Case 0A and Case 0B

Case	OFF			ON		
	G1	G2	G3	G1	G2	G3
CASE 0A	-	1-168	1-8, 22-31, 47-55, 71-79, 94-103, 118-168	1-168	-	9-21, 32-46, 56-70, 80-93, 104-117

CASE 0B	-	1-168	1-6, 23-30, 48-54, 72-78, 96-102, 119-137, 143-161, 166-168	1-168	-	7-22, 31-47, 55-71, 79-95, 103-118, 132, 137-142, 162-165

Case 1A) In this case, unit commitment and generation maintenance are optimized simultaneously without considering transmission limit constraints. The maintenance duration for all units is ten hours as stated in maintenance data. G1 and G3 are scheduled for maintenance at hours 119-128 and 156-165, respectively, which are the lowest load demand periods. When G1 is under maintenance, both G2 and G3 need to be committed for supporting system load, which would increase the overall cost. According to previous Case 0A, G2 is not operated over the entire week, thus it could be scheduled for maintenance at any time throughout the week. Therefore, there are multiple choices for scheduling G2's maintenance as it would not affect the system operating cost. In this case, the period during hours 1-10 is selected for maintaining G2. The schedule of generator maintenance can be referred to Table 12. Since line limits are not imposed, line violations occur on L1-2 and L1-4. The total cost obtained in this case is $528,943.49.

Case 1B) In this case, generation maintenance scheduling is optimized based upon the transmission limit constraints. The result shows that the maintenance hours for G1, G2 and G3 have been shifted to a new period which satisfy the line capacity requirement and at the same time at the lowest possible of operating cost. The new schedule for maintaining G1, G2 and G3 are during hours 143-152, 157-166, and 121-130, respectively. As a consequence, the operating cost obtained is $539 694.12, which is higher compared to Case OA. Generator maintenance schedule can be referred to Table 12.

Table 12: Generator Maintenance Schedule for Case 1A and Case 1B

Gen	**Case 1A**	**Case 1B**
G1	119-128	143-152
G2	1-10	157-166
G3	156-165	121-130

Case 2A) In this case, transmission maintenance is scheduled without transmission limit constraints. Here, L2-3 is selected for maintenance with the maintenance duration of 24 hours. The result shows that the optimal period for maintaining L2-3 is during hours 71-94 with the operating cost of $510 543.18. However, this schedule would result in lines violation occurred on L1-2 and L1-4.

Case 2B) In this case, the changes of transmission maintenance schedule due to transmission limit constraints can be clearly seen. From the result, it is found that the optimal schedule for L2-3 has been changed from hours 71-94 (in case 2A) to 120-143 when imposing the line limit constraints. This schedule gives the operating cost of $523 452.07, which is higher than case 2A, though it satisfies all lines limit capacity. The difference of the schedules between Case 2A and 2B can be shown in Table 13.

Table 13: Transmission Maintenance Schedule for Case 2A and Case 2B

Line	**Case 2A**	**Case 2B**
L2-3	71-94	120-143

Case 3A) In this case, the schedule of unit commitment, generation, and transmission maintenance are co-optimized simultaneously. Here, transmission limit constraints are not taken into consideration. The optimal period for maintaining G1, G2, G3, and L2-3 are during hours 119-128, 158-167, 94-103 and 8-31, respectively. It is noted that these schedules are totally different to the schedules suggested in case 1A and 2A. It is obvious that both generation and transmission are interrelated to each other and surely the coordination of both schedules would result in more optimal solution as the optimizer tried to find the best combination amongst them, in order to obtain the lowest possible of operating cost and satisfy all the restricted constraints. The operating cost yielded in this case is $528 943.49. Since no transmission limit is imposed on, there are also line violation occurred on certain hours on L1-2 and L1-4.

Case 3B) Similar to Case 3A, but now transmission limit constraints are taken into consideration. As a result, the maintenance schedule has changed significantly to satisfy the transmission limit constraints. The schedules proposed in this case is during hours 143-152, 54-63, 122-131, and 132-155, which is for G1, G2, G3, and L2-3, correspondingly. The operating cost for these schedules is $540 757.94. The maintenance schedule before (Case 3A) and after (case 3B) imposing line limit is compared in Table 14, while Table 15 summarizes the total cost obtained for all cases.

Table 14: Generator Maintenance Schedule for Case 3A and Case 3B

Equip	**Case 3A**	**Case 3B**
G1	119-128	143-152
G2	158-167	54-63
G3	94-103	122-131
L2-3	8-31	132-155

Table 15: Summary of Costs for all Cases ($)

Case	Maintenance Cost	Operation Cost	Total Cost
Case 0A	0	510 543.18	510 543.18
Case 0B	0	521 707.00	521 707.00
Case 1A	3760	528 943.49	532 703.49

Case 1B	3760	539 694.12	543 454.12
Case 2A	49920	510 543.18	560 463.18
Case 2B	49920	523 452.07	573 372.07
Case 3A	53 680	528 943.49	582 623.49
Case 3B	53 680	540 757.94	594 437.94

b) IEEE 118-Bus System

The IEEE 118-bus system consists of 54 thermal units, 186 branches, and 91 loads. The detailed data can be seen in motor.ece.iit.edu/data/coop. The maintenance data is shown in Table 16. The planning interval is one-week. The weekly peak load is 6000MW, and the load profile is the same as in Fig. 2. Four cases are studied as follows:

Case 0) Unit commitments with transmission limit constraints.
Case 1) Generator maintenance is imposed in Case 0.
Case 2) Transmission maintenance is imposed in Case 0.
Case 3) Both generator and transmission maintenance are imposed in Case 0.

Table 16: Equipment Maintenance Data for IEEE 118-Bus System

Equipment	From/At Bus	To Bus	Windows	Duration (h)	Cost ($/h)
U11	26	-	Mon-Sun	24	1200
U20	49	-	Mon-Sun	24	1000
U34	76	-	Mon-Wed	24	400
L51	38	37	Mon-Fri	18	5000

Case 0 is the base case, which considers the unit commitment without any equipment maintenance. In this system, base units U11 and U20 are operated over the entire week. Meanwhile, the peaking unit U34 supplies the load at hours 9-21, 31-46, 56-69, 80-94, and 105-118. The operating cost of Case 0 is $10,796,321.51. In Case 1, generation maintenance is co-optimized with unit commitment. U11, U20, and U34 are scheduled for maintenance at hours 145-168, 124-147, and 2-25, respectively. Due to the generation maintenance, the operating cost has increased to $10,866,796.80.

In Case 2, L51 is selected for maintenance and the best maintenance interval is during hours 42-59, which gives the lowest operating cost of $10,796,321.51. When integrating both generation and transmission maintenance in Case 3, the maintenance of L51 is shifted to the period of hours 103-120 as to minimize the operating cost. Meanwhile, the maintenance of U11, U20, and U34 are scheduled during hours 145-168, 121-144, and 3-26, respectively. These combinations give the operating cost of $10,867,593.86. Results of all four cases are summarized in Tables 17-18.

To evaluate the accuracy of the sensitivity analysis applied for the line flow calculation, the load flow program was performed using the PSSE simulator. In this assessment, the simulation was done for Case 3 at hour 116, which was the time when L51 is under maintenance. Simulation result is illustrated in Fig. 7. For the sake of discussion, only several lines are selected for verification. By comparing with the results in Table 19, all errors are within a small range, which guarantees the precision of the use of sensitivity factors in power flow calculations.

Table 17: Hourly Equipment Maintenance Schedule for all Cases

Equip	Case 0	Case 1	Case 2	Case 3
U11	-	145-168	-	145-168
U20	-	124-147	-	121-144
U34	-	2-25	-	3-26
L51	-	-	42-59	103-120

Table 18: Summary of Costs for all Cases ($)

Case	Maintenance Cost	Operation Cost	Total Cost
Case 0	0	10,796,321.51	10,796,321.51
Case 1	62,400	10,866,796.80	10,929,196.80
Case 2	90,000	10,796,321.51	10,886,321.51
Case 3	152,400	10,867,593.86	11,019,993.86

Table 19: Comparison Between Sensitivity Analyis and PSSE Simulator

Line	Sensitivity Analysis (MW)	PSSE Simulator (MW)	Error (%)
L30	63.478	63.4	0.12
L39	101.9476	101.9	0.04
L40	15.312	15.3	0.08

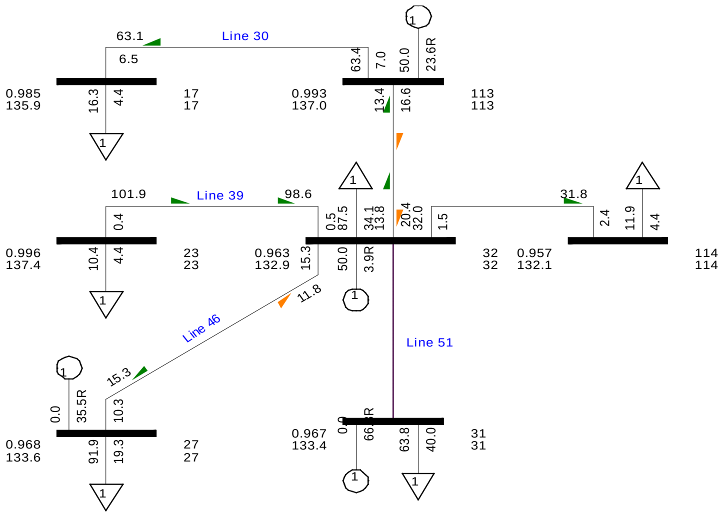


Fig. 7. Load flow calculation at hour 116 in Case 3 using PSSE

5. Summary

This paper highlights the importance of transmission limit constraints in maintenance scheduling problem. The simulation result has shown that maintenance schedule has changed to other hours when imposing transmission limit constraints to avoid line violation. The results indicate that the inclusion of line limit constraints could derive better solution as the maintenance is scheduled in periods of the lowest operating cost while guaranteed the system security.

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