Fast Heuristics for Transmission Outage Coordination

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***Abstract*—Preventive maintenance is key to extending the lifetime of transmission lines and to avoiding unnecessary replacement costs. Maintenance forces transmission assets to be taken out of service temporarily, which changes the network topology and may influence the system security margin as well as the energy markets. Therefore, transmission outage coordination is very critical. While industry practices typically examine the reliability impacts of outage coordination, this paper evaluates the impacts on both reliability and market economics. The procedure of practical outage coordination is first introduced in this paper. The extensive formulation to co-optimize the outage scheduling problem and the day-ahead unit commitment problem is then presented. The complete formulation with an exact algorithm can guarantee the optimal solution but that comes at the cost of a long solution time. Four fast heuristics are examined in order to solve this complex mathematical program. Case studies demonstrate the effectiveness of the four proposed heuristics. The solution time is significantly reduced while quality solutions are still obtained. The numerical results show that transmission outage coordination could have a great impact on the energy markets such as changes in LMP.**

***Index Terms*-- Energy markets, maintenance scheduling, outage coordination, power system reliability, power transmission economics.**

NOMENCLATURE

Indices:

t	Time period.
n	Bus.
k	Branch.
g	Generator.

Sets:

S_T	Set of time periods.
S_N	Set of buses.
S_K	Set of lines.
$S_{K(\text{n})}$	Set of lines connecting bus n.
$S_{K(\cdot,\text{n})}$	Set of lines with bus n as receiving bus.
$S_{K(\text{n},\cdot)}$	Set of lines with bus n as sending bus.
S_G	Set of generators.
$S_{\text{G(n)}}$	Set of generators at bus n.
S_M	Set of transmissions that request maintenance.

Parameters:

$P_g^{\max}$	Maximum capacity of generator g.
$P_g^{\min}$	Minimum capacity of generator g.
R_g^{SU}	Startup ramping rate of generator g.
R_g^{SD}	Shutdown ramping rate of generator g.
R_g^{hr}	Hourly ramping rate of generator g.
$P_g^{\min}$	Minimum capacity of generator g.
$P_g^{\min}$	Minimum capacity of generator g.
$P_k^{\max}$	Maximum capacity of branch k.
$P_k^{\min}$	Minimum capacity of branch k.
MT_k	Maintenance duration of transmission k.
UT_g	Minimum up time for generator g.
DT_g	Minimum down time for generator g.
c_g^{SU}	Startup cost for generator g.
c_g^{NL}	No load cost for generator g.
LD_{nt}	Load at node n in period t.
x_k	Reactance of line k.
M	A large number.
T	Number of time periods.
nb	Number of buses.

Variables:

Y_{kt}	Maintenance status of transmission line k in period t. 1 if under maintenance, 0 otherwise.
c_{kt}	1 if the maintenance process of transmission k starts in period t; 0 otherwise.
d_{kt}	1 if the maintenance process of transmission k ends in period t; 0 otherwise.
J_{kt}	Status of transmission k in period t, 1: on-service, 0: out-of-service service.
u_{gt}	Unit commitment variable for unit g in period t.
v_{gt}	Startup variable, 1 if the unit g is turned on in period t; 0 otherwise.
r_{gt}	Reserve from generator g in period t.

θ_{kt}	Angle difference across line *k* in period *t*.
LMP_{nt}	Location marginal price for bus *n* in period *t*.
$dLMP_{kt}$	*LMP* difference across line *k* in period *t*.
$AvLMP_t$	System average LMP in period *t*.
F_{kt}^{+}, F_{kt}^{-}	Flowgate price of line *k* in period *t*.
$dumCost_{kt}$	Pseudo cost of starting the maintenance process for line *k* in period *t*.

I. Introduction

As load grows rapidly over time, power systems become much more stressed than before. Facilities that are heavily loaded experience a decrease in their useful life and accelerate the aging of power system infrastructure. The facility replacement cost could be very high. However, regular maintenance can largely extend their lifetime and, hence, the annual replacement cost will be reduced and the total costs will decrease accordingly.

Taking equipment in stressed power systems out of service for maintenance may increase system operating cost and cause security issues. Therefore, coordinating the outages of these various facilities properly is a very critical problem, which is referred to as outage coordination. Appropriate scheduling of such preventive maintenances may reduce the overall cost while the system reliability is retained.

The power system, with scheduled outages, should be operated at least in a secure and reliable way. Efficient and economical operation is also highly desired. Improper outages may cause a large amount of congestion and reduce system reliability. However, with appropriately scheduled outages, the overall operational efficiency of the entire system can increase while its ability to maintain operational security is retained.

There are two types of outages: planned outage and unplanned outage. Unplanned outages normally mean the failure of elements in real-time operation. Planned outages are for maintenance. The time window of an outage can range from several minutes to months. Thus, outage coordination problems consist of long-term scheduling and short-term scheduling. The maintenance work for a transmission asset can be completed either in continuous periods or multiple discrete intervals. Planned transmission outages can be considered as a form of topology control [1]-[3] since it is a transmission switching problem where a subset of lines are planned to be taken out of service for some length of time. While it is generally thought that fewer transmission assets in service results in worse system performance, prior work [4]-[6] on optimal transmission switching has shown that this is not always true.

An integrated methodology for outage coordination was proposed in [7], in which reliability, maintenance, and failure costs are all considered. A unit maintenance scheduling (UMS) coordination mechanism was proposed in [8]. Reference [9] presented a coordination strategy between long-term and short-term generation scheduling. A stochastic model for optimizing long-term maintenance scheduling with short-term security-constrained unit commitment (SCUC) was proposed in [10]. Though a lot of efforts have been devoted to improve the outage coordination problem, limited work has been done to analyze the effect of a scheduled outage on energy markets and investigate the relationship between market signals and outage scheduling.

This paper is focused on short-term transmission outage coordination. By modeling outages into the formulation of day-ahead unit commitment problem, the optimal solution can be guaranteed. In this paper, such an extensive model for the outage coordination problem is first proposed to determine the best outage scheduling along with generation dispatch scheduling. Four heuristic approaches are then proposed to speed up the solution time. The impact of outage coordination on system reliability and energy markets are also analyzed.

The rest of the paper is organized as follows. Industry practices on the outage coordination problem are introduced in section II. The extensive formulation considering both security-constrained unit commitment (SCUC) and transmission outage coordination is proposed in section III. Section IV briefly introduces the four proposed heuristics; case studies are shown in section V. Section VI concludes the paper and section VII presents potential future work.

II. Industry Practices

It is desirable that transmission owners (TOs) submit the outage requests to the independent system operator (ISO) as soon as possible, which benefits the entire system and all market participants due to the following reasons:

- With more time, the ISO could better evaluate the effect of outages on system reliability and energy markets and make more reasonable decisions;
- Opportune announcement of outage information makes energy markets transparent and enables market participants to better estimate the markets and, hence, react to it more properly;
- The impact of transmission outages on the financial transmission rights (FTRs) market is lessened if accurate network topology information with scheduled transmission outages is provided in advance;

Outage elements that are close to the boundary of a power system can impose impact on its neighboring systems. Thus, those outages should be coordinated with the neighboring areas.

Though the implementations of transmission outage coordination are different between ISOs, the fundamental procedures are very similar. The following steps present the basic process of how transmission outage coordination is conducted by ISOs [11]-[13].

1) TOs submit outage requests.

2) ISOs estimate the impacts of outages on system reliability and energy markets by conducting sufficient simulations.
3) Based on the evaluation, ISOs approve or deny TOs' outage requests.
4) TOs either perform maintenance as scheduled, or come back to step 1) and re-submit the outage requests if previous request is denied.

The following sub-section shows how ISO New England (ISO-NE) performs outage coordination.

A. *ISO New England*

For an outage to be considered as short-term process in ISO-NE territory, the request should be submitted in advance of 1 day to 20 days [11]. Fig. 1 [11] shows the pattern between the number of outages planned to start in each month and the monthly peak load in 2014. Obviously, more outages were requested in months with lower peak load. The similar figures for years 2011 - 2013 in the same report also indicate that the number of outages and the monthly peak load are inversely proportional. Reference [11] mentions that ISO-NE can exercise the ability to reschedule transmission outages if needed to ensure the reliable operation of the system, reduce congestion cost, and minimize market impact.

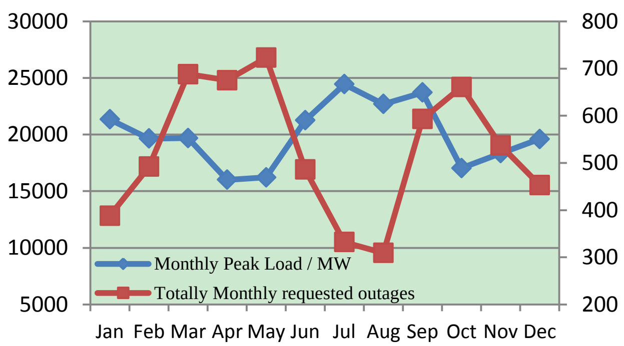

Fig. 1 Transmission equipment outages planned to start in each month in 2014 compared with monthly peak load within ISONE area [11]

III. Mathematical Formulation

To optimize the scheduling of transmission outages, the following mathematical model is proposed. Three types of constraints are taken into consideration in the proposed formulation for the outage coordination problem. They are listed as follows:

- Transmission maintenance constraints.
- SCUC constraints.
- Coupling constraints.

The objective function is described in detail in the following sections as well as the three sets of constraints.

A. *Objective Function*

The objective function is to minimize the total cost as shown in (1). The three terms in this objective function denote operating cost, no load cost, and start-up cost, respectively.

$$\text{Min} \sum_{g \in S_G} \sum_{t \in S_T} (c_g P_{gt} + c_g^{NL} u_{gt} + c_g^{SU} v_{gt}) \qquad (1)$$

B. *Transmission Maintenance Constraints*

Due to resource limitation and crew availability, not all transmission assets can be scheduled during the same interval and several transmission assets may not be available for maintenance in specific periods in the outage coordination timeframe. For simplicity, these constraints are not considered in this paper. However, the model used in this paper can easily incorporate these constraints without any major change [14].

The example, that line k is scheduled to be out of service from period 3 to period 7 for maintenance, shown in Table I illustrates the relationship of the three variables, c_{kt}, d_{kt}, and Y_{kt}, which are used to form the transmission maintenance constraints. They are listed below.

Table I Example of the relationship between Y_{kt}, c_{kt}, d_{kt}

			Periods that transmission k is under maintenance							
Period t	1	2	3	4	5	6	7	8	9	…
Y_{kt}	1	1	**0**	**0**	**0**	**0**	**0**	1	1	
c_{kt}	0	0	**1**	0	0	0	0	0	0	
d_{kt}	0	0	0	0	0	0	0	**1**	0	

The transmission maintenance constraints are listed from (2) through (8):

$$c_{kt} - d_{kt} = Y_{k,t\text{-}1} - Y_{kt}, \quad \forall k, t \geq 2 \qquad (2)$$

$$c_{k1} - d_{k1} = 1 - Y_{k1}, \quad \forall k \qquad (3)$$

$$c_{kt} + d_{kt} \leq 1, \quad \forall k, t \qquad (4)$$

$$\sum_t (1 - Y_{kt}) = MT_k, \quad \forall k \in S_M \qquad (5)$$

$$\sum_t c_{kt} = 1, \quad \forall k \in S_M \qquad (6)$$

$$Y_{kt} = 1, \quad \forall k \notin S_M, t \qquad (7)$$

$$c_{kt}, d_{kt}, Y_{kt} \in \{0,1\}, \quad \forall k, t \qquad (8)$$

Constraints (2) and (3) define the relationship between c_{kt}, d_{kt}, and Y_{kt}. Constraint (4) ensures that the maintenance cannot start and end at the same period. Constraint (5) guarantees that the maintenance process would last for MT_k periods as requested. The maintenance needs to be performed in the time frame of concern, which is guaranteed by (6). The transmission assets that do not request for outage are all in service (7). c_{kt}, d_{kt}, and Y_{kt} are all binary variables as presented in (8).

C. *SCUC Constraints*

The SCUC constraints used in this paper are listed in (9)-(24):

$$P_g^{\min} u_{gt} \leq P_{gt}, \quad \forall g, t \qquad (9)$$

$$P_{gt} + r_{gt} \leq P_g^{\max} u_{gt}, \quad \forall g, t \qquad (10)$$

$$0 \leq r_{gt} \leq R_g^{10} u_{gt}, \quad \forall g, t \qquad (11)$$

$$\sum_{i \in G} r_{it} \geq P_{gt} + r_{gt}, \quad \forall g, t \tag{12}$$

$$\sum_{i \in G} r_{it} \geq 7\% \cdot \sum_{n} d_{nt}, \quad \forall t \tag{13}$$

$$P_{gt} - P_{g,t-1} \leq R_g^{hr} u_{g,t-1} + R_g^{SU} v_{gt}, \quad \forall g, t \tag{14}$$

$$P_{g,t-1} - P_{g,t} \leq R_g^{hr} u_{g,t} + R_g^{SD} (v_{gt} - u_{gt} + u_{g,t-1}), \quad \forall g, t \tag{15}$$

$$\sum_{w=t-UT_g+1}^{t} v_{gw} \leq u_{gt}, \quad \forall g, t \geq UT_g \tag{16}$$

$$\sum_{w=t+1}^{t+DT_g} v_{gw} \leq 1 - u_{gt}, \quad \forall g, t \leq T - DT_g \tag{17}$$

$$v_{gt} \geq u_{gt} - u_{g,t-1}, \quad \forall g, t \tag{18}$$

$$0 \leq v_{gt} \leq 1, \quad \forall g, t \tag{19}$$

$$\sum_{g \in S_{G(n)}} P_{gt} + \sum_{k \in S_{K(\cdot,n)}} P_{kt} - \sum_{k \in S_{K(n,\cdot)}} P_{kt} = LD_{nt}, \quad \forall n, t \tag{20}$$

$$J_{kt} P_k^{\min} \leq P_{kt} \leq J_{kt} P_k^{\max}, \quad \forall k, t \tag{21}$$

$$P_{kt} - \theta_{kt} / x_k \leq M(1 - J_{kt}), \quad \forall k, t \tag{22}$$

$$-M(1 - J_{kt}) \leq P_{kt} - \theta_{kt} / x_k, \quad \forall k, t \tag{23}$$

$$u_{gt} \in \{0, 1\}, \quad \forall g, t \tag{24}$$

The generation of each on-line generator is bounded by its minimum limit (9). The sum of the output and reserve of a unit cannot exceed its maximum limit (10), which ensures that the generation will not violate the capacity limit. The reserve provided by a unit should be within its 10 minutes ramping capability (11). The "biggest generator" rule and the 7% of the demand rule [15] are used for the system reserve requirements, as defined in constraints (12) and (13). Ramping constraints between two consecutive periods are modeled as (14)-(15). Generator minimum on/off time are guaranteed by (16)-(17). The start-up variables are constrained by the unit commitment variables (18), and it has to be within the range between 0 and 1 (19). Note that the start-up variables *v* are defined as continuous variables in this model. However, the final solutions will always be binary values, either one or zero, once the unit commitment variables *u* are determined [16]. Power balance between the generation and demand is constrained in (20). Network constraints are presented in (21)-(23). The unit commitment variables u_{gt} are binary variables (24).

D. Coupling Constraints

Equation (25) ensures that transmission lines will not be in service if it is under maintenance, by which constraint the above two sets of constraints are bundled.

$$J_{kt} = Y_{kt}, \quad \forall k, t \tag{25}$$

If transmission switching is considered in the outage coordination problem, (26) could be used to replace (25). A lower cost could be achieved with additional flexibility provided by transmission switching [1]-[2]. For simplicity, transmission switching is not modeled in this paper.

$$J_{kt} \leq Y_{kt}, \quad \forall k, t \tag{26}$$

IV. HEURISTIC METHODS

By combining the outage coordination problem with unit commitment problem, an optimal solution that considers the impacts on the economic unit commitment solution can be obtained. However, this would increase the computational complexity and, thus, take a longer solution time. For large-scale systems, it may be not able to solve this complex co-optimization problem in a reasonable timeframe. Thus, fast heuristic approaches, which provide quality solutions with limited time, are desirable. In this paper, four heuristic methods are proposed as follows:

- Flowgate pricing heuristic (FPH)
- Congestion rent heuristic (CRH)
- LMP pricing heuristic (LPH)
- Reliability heuristic (RH)

The responses of market pricing signals to different transmission outages could vary significantly. Therefore, the four heuristics are essentially sensitivity based approaches. For each heuristic method, a pseudo cost is associated with each period when the outage is scheduled to start. The pseudo cost $dumCost_{kt}$ for starting the maintenance at period *t* for line *k* is defined in (27), (28), (30), and (31) for FPH, CRH, LPH, and RH, respectively.

All four heuristic methods use the same procedure, which is listed below:

1) Solve a basic SCUC problem without modeling the outage constraints,
2) Calculate the pseudo costs $dumCost_{kt}$,
3) Determine the period that is associated with the minimum pseudo cost for starting the maintenance,
4) Verify that the solution is feasible by solving the basic SCUC problem again with the updated topology from step 3).

Note that step 4) is to guarantee that the system is still reliable with the outages determined by the heuristic methods.

$$dumCost_{kt} = \sum_{s=t}^{t+MTK_k-1} (F_{ks}^{+} + F_{ks}^{-}), k \in \Omega_M, t \leq T - MTK_k + 1 \tag{27}$$

$$dumCost_{kt} = \sum_{s=t}^{t+MTK_k-1} abs(dLMP_{ks} * P_{ks}), k \in \Omega_M, t \leq T - MTK_k + 1 \tag{28}$$

where,

$$dLMP_{kt} = LMP_{kt,t} - LMP_{kf,t} \tag{29}$$

$$dumCost_{kt} = \sum_{s=t}^{t+MTK_k-1} dLMP_{ks}, \quad k \in \Omega_M, t \leq T - MTK_k + 1 \tag{30}$$

$$dumCost_{kt} = \sum_{s=t}^{t+MTK_k-1} (P_{ks} / P_k^{\max})^2, \quad k \in \Omega_M, t \leq T - MTK_k + 1 \tag{31}$$

The $dumCost_{kt}$ defined in (31) for RH method also reflects the available transmission margins. Smaller $dumCost_{kt}$ value means higher available transmission margins.

V. CASE STUDIES

The proposed model, based on an exact solution as well as on the proposed heuristic approaches, is solved in AMPL [17]. Gurobi [18] with version 6.0.4 is chosen as the MILP solver. The computer platform is 64-bit Windows 7 Enterprise operating system, of which the processor is 3.40 GHz with four Intel(R) Core(TM) i7-3770 CPUs.

The system used to demonstrate the effectiveness of the proposed methods in this paper is the IEEE 24-bus system - one area of IEEE RTS-96 system [19]. The time limit for Gurobi is set to 180s and the relative mipgap is set to 1e-6. The resolution is one hour while the time frame simulated is 24 hours.

Fig. 2 [20] shows the network topology of IEEE 24-bus system with bus number and branch number on it. The load profile of this test case is shown in Fig. 3.

Two separate cases of outages are studied:

- One single line outage: line 27.
- Three lines outage: line 8, line 21, line 31.

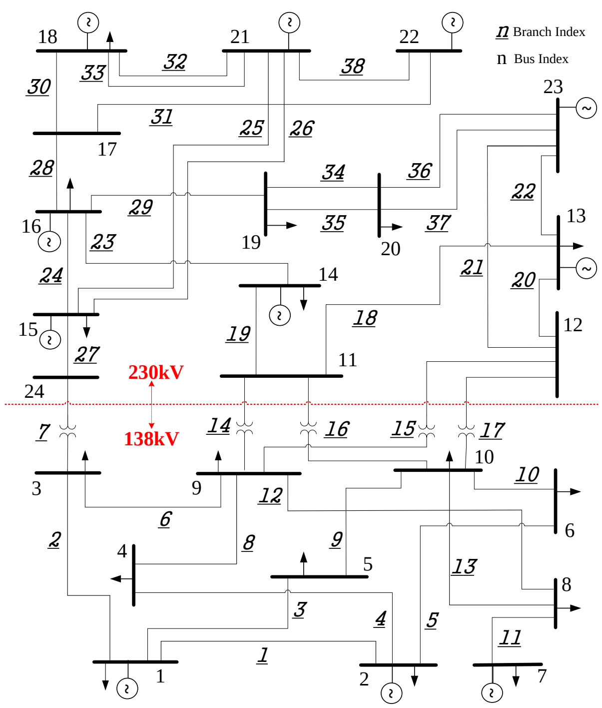

Fig. 2 IEEE 24-bus system - one area of IEEE RTS-96 system [20]

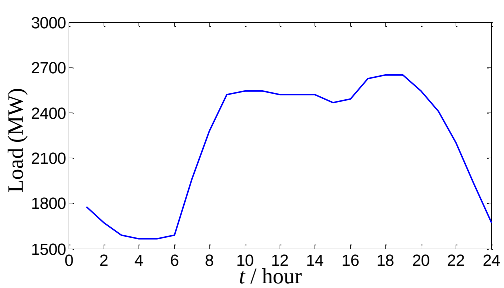

Fig. 3 24-hour load profile for IEEE 24-bus system

A. Single Line Outage

Line 27 requests a four hour downtime for maintenance. The optimal solution is obtained by solving the extensive model: the outage for line 27 is scheduled from hour 3 to hour 6.

By solving the basic SCUC problem and applying the heuristic methods, the periods of line 27 outage are then determined with each heuristic method. The detailed results are shown in Table II. The CRH and LPH methods can achieve the same optimal solution with the extensive model while the computational time is largely reduced. The solution time for solving the basic SCUC problem is over 10 times faster than the extensive model. Even if the time for verifying the feasibility of the scheduled outages is added to the heuristic methods, CRH and LPH methods are still about 5 times faster. As for the other two heuristics, FPH and RH, different maintenance schedules are obtained. Though the associated total costs increase, they are still within an acceptable range. Though it is unexpected that the computational time T_2 for RH is longer than the extensive model, it is definitely possible, since less constraints and variables do not absolutely guarantee less solution time.

Table II Results of line 27 outage scheduling problem

Method	Total cost (k$)	Scheduled hours	Solution time (seconds)	
			T_1	T_2
Ext	1145.3	3-6	14.43	
FPH	1159.5	1-4	1.36	3.32
CRH	1145.3	3-6		1.61
LPH	1145.3	3-6		1.61
RH	1186.6	21-24		25.52

T1: the time to solve the basic SCUC problem.
T2: the time to solve the SCUC problem with the updated topology.

Table III shows the market results with and without the line 27 outage. With line 27 out of service during hours 3 - 6, the total load payment, generator cost, and congestion rent increase while the generator rent and generator revenue decrease.

Table III Market results with and without line 27 outage

Model	LP /k$	Generator /k$			CR /k$
		Cost	Rent	Revenue	
Ext	3890.7	1145.3	1129.7	2275.0	1615.7
Basic	3850.3	1133.3	1156.4	2289.8	1560.6

LP denotes the load payment; CR denotes the congestion rent.

Though the statistic numbers in Table III are for the whole system over all the simulated 24 hours, the differences only exist in hours 3, 4, 5, and 6. For the other 20 hourly periods, the costs and prices are the same.

$AvLMP_t$ denotes the system average LMP in period t, which is defined in (32).

$$AvLMP_t = \sum_{n \in S_N} LMP_{n,t} \Big/ nb \tag{32}$$

The difference of $AvLMP_t$ between the extensive model and the basic model is shown in Fig. 4. The system average $LMPs$ gained from these two models are different only during the four hours when line 27 is out of service for maintenance purposes.

Fig. 5 shows the LMP curves of the extensive model and the basic SCUC model in hour 3. As shown in Fig. 5, the LMP curve under the full network condition is quite flat while it is much more variable under the network condition with the outage of line 27, which changes the system topology.

During the hours when line 27 is under maintenance, generations of the cheaper units of buses 15, 16, 18, and 21 decrease while the expensive units of buses 1 and 2 increase their dispatch points. This increases the total costs for those hours and changes the whole system operating condition including LMPs and congestions.

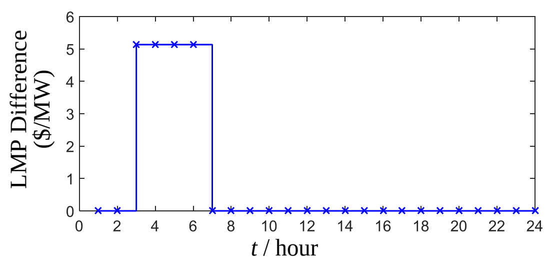

Fig. 4 LMP difference between the extensive model and the basic SCUC model

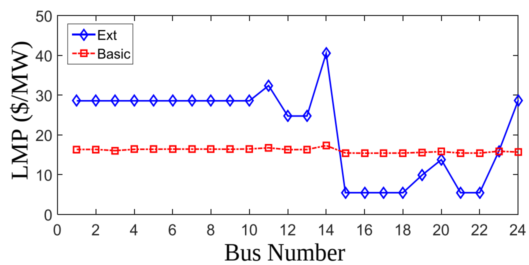

Fig. 5 LMP curves of the extensive model and the basic SCUC model in hour 3

B. *Multiple Lines Outage*

In this case, multiple lines outages are taken into consideration. Table IV shows the outages information in detail.

Table IV Information of multiple line outages

Line to be maintained	From Bus Number	To Bus Number	Maintenance Duration (hours)
8	4	9	6
21	12	23	8
31	17	22	6

The outage scheduling results of the extensive model and the heuristic methods are shown in Table V. Though none of the heuristics achieves the same schedule as the full extensive model, their total costs are very similar. The incremental total costs of CRH and LPH heuristics compared to the extensive model are less than 5% while it is well below 1% for FPH and RH heuristics. For multiple outages, the solution time saved by the heuristic is much more than that of the single outage coordination problem. Since multiple outages are coordinated in real-life, it is important to have an algorithm that produces good solutions within moderate timeframes.

Table V Results of multiple lines outage scheduling problem

	Total cost (K$)	Scheduled hours			Solution time (seconds)	
		line 8	line 21	Line 31	T_1	T_2
Ext	1177.6	15-20	2-9	9-14	55.26	
FPH	1180.4	1-6	1-8	1-6	1.36	2.04
CRH	1232.8	1-6	17-24	1-6		7.52
LPH	1232.8	1-6	17-24	1-6		7.52
RH	1178.8	7-12	1-8	7-12		2.18

T1: the time to solve the basic SCUC problem.
T2: the time to solve the SCUC problem with the updated topology.

VI. Conclusions

Preventive maintenance is critical to extend the lifetime of transmission lines and to avoid unnecessary facility replacement costs. Improperly scheduled outages may largely reduce the system reliability margins. Thus, outage coordination is an essential problem in power system operation. An extensive model was first proposed in this paper to achieve the best solution but that comes with the cost of having a long computational time. Therefore, four heuristic methods are proposed in this paper to replace the extensive model since an exact algorithm may not be solvable for large-scale systems. Case studies verify that the four proposed heuristics can significantly reduce the solution time while quality solutions are still obtained. The simulation results also show that transmission outage coordination can have significant impacts on energy market settlements.

VII. Future Work

Large-scale practical systems are needed to demonstrate the robust and effectiveness of the proposed four heuristic methods. Generator outages are very common in practice; thus, heuristic methods for generator outage coordination are also desired.

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