CO-OPTIMIZATION OF TRANSMISSION TOPOLOGY AND GENERATION DISPATCH INCORPORATING DEMAND RESPONSE AND RENEWABLE ENERGY UNCERTAINTY IN DAY-AHEAD ELECTRICITY MARKETS

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Abstract - The variability of renewables requires a higher degree of flexibility in power system operation. At present, there are a variety of solutions which are being utilized, particularly demand response and transmission switching. This paper presents a model for co-optimization of transmission topology and generation dispatch based on a two-stage stochastic optimization. Demand response and renewable energy uncertainty are integrated into the proposed model. The uncertainty pertaining to renewable energy sources is presented through a set of scenarios. The model is a mixed-integer linear programming (MILP) problem and can be applied for the day-ahead market clearing. The results implemented using a 5-bus system demonstrate the effectiveness of the proposed model.

Key words - Transmission switching; day-ahead market clearing; demand response; renewables; mixed-integer linear programming (MILP).

1. Introduction

Nowadays, the issue of climate change has required the pressing need for limiting industrial emissions of greenhouse gases. In addition to the tragic consequences of climate change, there is an energy crisis in many countries in the world due to the depletion of fossil fuels. Therefore, renewable energy has been prominent in most industrialized countries with the aim of decarbonizing in the electricity sector as well as meeting the rising demand for energy and safeguarding the security of energy supply. Solar energy, wind, geothermal, biomass, waves and hydrogen energy are major renewables. Wind power generation is the most widely used source of renewable energy around the world, while solar energy is catching up at a rapid pace. Power producers have strong incentives to develop renewable energy such as policies which help them to sidestep most of the drawbacks and risks implied by the participation in the market. Additionally, the per-unit cost of renewable energy has constantly reduced, which gives renewables advantages to compete in the marketplace with conventional energy production means. Indeed, most of generation technologies based on renewable sources are non-dispatchable and their production is stochastic. The exploitation of these renewables whose generation cost is generally low requires the availability of flexible production capacity as a backup as reserve [1]. The flexibility can be attained from either the supply side such as combined cycle gas turbine (CCGT) units or the demand side, for example demand response [2]-[3]. Furthermore, transmission switching also provides a means of enhancing the transmission network flexibility and improving the effectiveness of market operation [4], [5].

Traditional formulations of the optimal power flow (OPF) problem are described in [6]. In this paper, authors applied an iterative DCOPF-based algorithm with fictitious nodal demand (FND) model to calculate locational marginal price (LMP). However, in this model, demand is assumed to be inelastic and the problem is not time coupled. A tool for unit commitment schedule in day-ahead based electricity markets is developed in [7] in which time coupled constraints are integrated such as constraints on ramp-rate, minimum up-time and minimum down-time. Authors in [8] incorporated transmission losses and Thyristor Controlled Series Compensators (TCSC) into a multi-period linearized OPF. Nonetheless, only conventional power producers are considered and authors assumed demand to be fixed.

To take account of the variable and partly-predictable nature of renewables, the extended OPF problem is presented in [9], [1] and [10] in which the uncertainty of the wind generation is addressed by means of scenarios and fixed demand is also considered. Moreover, these OPF problems are one-stage stochastic optimization. A demand response (DR) model is introduced in [11], [12] in which authors proposed an optimization framework for the DR aggregation in wholesale electricity markets and day-ahead markets. Taking into account of joint wind power sources and demand-side participation in electricity market operation is considered in [13] and [14] in which a two-stage optimization approach pertaining to the scenarios is employed. Nevertheless, transmission lines are presumed to be uncontrollable in the aforementioned papers. The formulation of the problem of finding an optimal generation dispatch and transmission topology to meet a specific inflexible load is a mixed integer program [4], [15]. The optimal transmission switching problem can be deployed as a congestion management tool [16], thereby promoting electricity market efficiency. The optimal transmission switching for power systems with large-scale renewables in day-ahead markets is a stochastic unit commitment [17].

Much of the work in this area is irrelevant to co-optimizing transmission topology and generation dispatch considering demand response in combination with renewable energy uncertainty.

The main contributions of this paper are threefold:

- A multi-period linearized OPF formulation based two-stage stochastic optimization for co-optimization transmission switching and generation dispatch with jointly integrated demand response and renewable energy uncertainty;

- A rigorous mathematical model of demand response;

- The effect of demand shift and transmission switching on both locational marginal prices and cost of generation is analyzed in detail.

The paper is organized as follows: section 2 presents the general mathematical formulation of the two-stage stochastic problem. Section 3 describes the linearization method based big-M to convert the nonlinear problem to the mixed-integer linear formulation. Numerical results are given in Section 4 and the conclusions are presented in Section 5.

2. General mathematical formulation

In this section, a two-stage stochastic model which describes the interdependent between the two stages is presented. The dispatch of conventional generators is determined in the first stage. The second stage realizes the generating scenarios of renewable energy sources. The demand response and slight adjustments of operating points of the conventional units mitigate supply-generation imbalance. It is assumed that distribution companies which generally manage demand response programs can bid both demand and the flexibility for each time in a given time horizon. The independent system operator (ISO) can either meet the demand or use the flexibility to facilitate the uncertainty from renewables.

2.1. Objective function

The objective function of the multi-period optimal power flow problem based two-stage stochastic model for market clearing is minimization of the so-called expected system operation costs, which is composed of both the cost associated with the day-ahead energy dispatch of conventional generators and the expected cost of anticipated balancing to be taken during the real-time operation of the power system.

The objective function over the given time horizon T can be described explicitly as follows:

$$\min \sum_{t \in T} z$$

$$z = \sum_{g \in G} f(P_{g,t}^{G}) + \sum_{s \in S} \lambda_{\mathrm{w},s} \begin{bmatrix} \sum_{\mathrm{w} \in \mathrm{W}} C_{\mathrm{w},t}^{\mathrm{w}} . P_{\mathrm{w},s,t}^{spill} \\ + \sum_{d \in D} (C_{\mathrm{d},t}^{\mathrm{D+}} . \alpha_{d,s,t}^{+} + C_{\mathrm{d},t}^{\mathrm{D-}} . \alpha_{d,s,t}^{-}) P_{d,t}^{D} \\ + \sum_{g \in G} (C_{\mathrm{g},t}^{\mathrm{R+}} . \Delta P_{\mathrm{g},s,t}^{G+} + C_{\mathrm{g},t}^{\mathrm{R-}} . \Delta P_{\mathrm{g},s,t}^{G-}) \end{bmatrix} \tag{1}$$

This objective is subject to two different sets of constraints, namely, the constraints involving energy variables in the day-ahead dispatch; the equations constraining the utilization of balancing resources.

2.2. Day-ahead stage constraints

The constraints for the first stage, i.e., day-ahead operation, is described as follows:

$$\sum_{g \in G_b} P_{g,t}^{G} + \sum_{\mathrm{w} \in W_b} P_{\mathrm{w},t}^{W} - \sum_{d \in D_b} P_{\mathrm{d},t}^{D} = \sum_{l \in L_1} P_{l,t}^{L} - \sum_{l \in L_2} P_{l,t}^{L}; \quad \forall g \in G, \forall \mathrm{w} \in \mathrm{W}, \forall d \in D, \forall l \in L, \forall t \in T \tag{2}$$

$$P_{l,t}^{L} = \frac{1}{x_l}(\delta_{b,t} - \delta_{b',t}); \forall l \notin J, \forall b \in N, \forall b' \in N, \forall t \in T \tag{3}$$

$$P_{l,t}^{L} = z_{l,t} \frac{1}{x_l}(\delta_{b,t} - \delta_{b',t}); \forall l \in J, \forall b, b' \in N, \forall t \in T \tag{4}$$

$$z_{l,t} = \{0,1\}; \forall l \in J, \forall t \in T \tag{5}$$

$$P_{g}^{G-} \le P_{g,t} \le P_{g}^{G+}; \forall g \in G, \forall \mathrm{t} \in \mathrm{T} \tag{6}$$

$$-R_{g}^{U} \le P_{g,t}^{G} - P_{g,t+1}^{G} \le R_{g}^{D}; \forall g \in G, \forall t = 1, 2, ..., 23 \tag{7}$$

$$-P_{l}^{\max} \le P_{l,t}^{L} \le P_{l}^{\max}; \forall l \in L, \forall t \in T \tag{8}$$

$$0 \le P_{w,t}^{W} \le P_{w,t}^{W\max}; \forall w \in W, \forall t \in T \tag{9}$$

$$\sum_{l \in J} (1 - z_{l,t}) \le J; \quad \forall t \in T \tag{10}$$

$$\delta_b = 0; \; b : reference\ node \tag{11}$$

Where J denotes the maximum number of open transmission lines.

The constraints (2) enforce the power balance at every node and every hour. Equations (3) and (4) define the power flows through non-dispatchable and dispatchable transmission lines, respectively, which are limited by the corresponding capacity limits by constraints (8). Constraints (5) define binary variables $z_{l,t}$ that indicate whether a dispatchable line is in service ($z_{l,t} = 1$) or out of service ($z_{l,t} = 0$). Constraints (6) and (9) impose bounds for the power produced by conventional generating units and renewables, respectively. Constraints (7) is the ramp-up and ramp-down constraints. Constraints (10) are introduced to limit the number of integer variables which severely impact on the computational performance. This constraint is used to gain understanding about the effects of changing the network topology. Finally, the voltage angle of the reference node is fixed to zero. The network is represented using a DC model without losses.

2.3. Balancing stage constraints

The real-time operation for each scenario s is constrained by equations (12)-(26).

$$\sum_{g \in G_b} \left(P_{g,t}^{G} + \Delta P_{g,s,t}^{G}\right) + \sum_{\mathrm{w} \in W_b} (P_{\mathrm{w},s,t}^{\mathrm{W}} - P_{w,s,t}^{spill}) = \sum_{d \in D_b} (P_{\mathrm{d},t}^{D} + \Delta P_{d,s,t}^{D}) + \sum_{l \in L_1} P_{l,\mathrm{s},t}^{L} - \sum_{l \in L_2} P_{\mathrm{l,s},t}^{L}; \quad \forall g \in G, \forall \mathrm{w} \in \mathrm{W}, \forall d \in D, \forall l \in L, \forall t \in T, \forall s \in S \tag{12}$$

$$P_{l,\mathrm{s},t}^{L} = \frac{1}{x_l}(\delta_{b,\mathrm{s},t} - \delta_{b',\mathrm{s},t}); \quad \forall l \notin J, \forall s \in S, \forall b, b' \in N, \forall t \in T \tag{13}$$

$$P_{l,\mathrm{s},t}^{L} = z_{l,\mathrm{s},t} \frac{1}{x_l}(\delta_{b,\mathrm{s},t} - \delta_{b',\mathrm{s},t}); \quad \forall l \in J, \forall s \in S, \forall b, b' \in N, \forall t \in T \tag{14}$$

$$z_{l,\mathrm{s,t}} = \{0,1\}; \forall l \in J, \forall t \in T, \forall s \in S \tag{15}$$

$$P_{g}^{G-} \le P_{g,t}^{G} + \Delta P_{g,s,t}^{G} \le P_{g}^{G+}; \forall g \in G, \forall t \in T, \forall s \in S \tag{16}$$

$$\Delta P_{g,s,t}^{G} = \Delta P_{g,s,t}^{G+} - \Delta P_{g,s,t}^{G-}; \quad \forall g \in G, \forall t \in T, \forall s \in S \tag{17}$$

$$0 \le \Delta P_{g,s,t}^{G+} \le R_{g,t}^{+}; \; \forall g \in G, \forall t \in T, \forall s \in S \tag{18}$$

$$0 \le \Delta P_{g,s,t}^{G-} \le R_{g,t}^{-}; \forall g \in G, \forall t \in T, \forall s \in S \tag{19}$$

$$\Delta P_{d,s,t}^{D} = (\alpha_{d,s,t}^{+} - \alpha_{d,s,t}^{-}) \mathrm{P}_{d,t}^{D}; \quad \forall d \in D, \forall t \in T, \forall s \in S \tag{20}$$

$$0 \le \alpha_{d,s,t}^{+} \le F_{d,t}^{+} - 1; \quad \forall d \in D, \forall t \in T, \forall s \in S \tag{21}$$

$$0 \le \alpha_{d,s,t}^{-} \le 1 - F_{d,t}^{-}; \forall d \in D, \forall t \in T, \forall s \in S \tag{22}$$

$$\sum_{t\in T_D^F}(P_{d,t}^D+\Delta P_{d,s,t}^D)=\sum_{t\in T_D^F}P_{\mathrm{d},t}^D;\quad \forall d\in D,\forall s\in S \tag{23}$$

$$P_{w,s,t}^{spill}\le P_{w,s,t}^{\mathrm{W}};\quad \forall \mathrm{w}\in W,\forall t\in T,\forall s\in S \tag{24}$$

$$-P_l^{\max}\le P_{l,s,t}^L\le P_l^{\max};\quad \forall l\in L,\forall t\in T,\forall s\in S \tag{25}$$

$$\sum_{l\in J}(1-z_{l,s,t})\le J;\ \forall l\in L,\forall t\in T,\forall s\in S \tag{26}$$

The constraints (12) define the generation-demand balance at every node, every hour and every scenario. Equations (13) and (14) define the power flows through non-dispatchable and dispatchable transmission assets, respectively, which are limited by constraints (25). Constraints (15) define binary variables $z_{l,s,t}$ that indicate whether a dispatchable line is in service ($z_{l,s,t}$ = 1) or out of service ($z_{l,s,t}$ = 0). Constraints (16) and (24) impose limits for the power produced by conventional generators and the power spilled by renewable energy sources, respectively. Constraints (26) are introduced to limit the number of integer variables which is in line with the day-ahead stage.

Constraints (17), (18) and (19) define the second stage recourse variable $\Delta P_{g,s,t}^G$ in terms of the upward and the downward regulation variables $\Delta P_{g,s,t}^{G+}$ and $\Delta P_{g,s,t}^{G-}$. Likewise, constraints (20), (21) and (22) model the demand response. Let $[F_{d,t}^+,F_{d,t}^-]$ be the flexibility interval of demand at bus *d* and at the time period *t*. Thus, we have $0\le F_{d,t}^-\le 1$ and $F_{d,t}^+\ge 1$. If the demand at bus *d* is not flexible, then $F_{d,t}^+=F_{d,t}^-=1$ are used. Moreover, we introduce two positive continuous variables $\alpha_{d,s,t}^+,\alpha_{d,s,t}^-$ which give the increase and decrease in the amount of real power of demand at bus *d*, respectively. Equations (23) impose the conservation of the demand. If a demand at bus *d* is flexible in the time window $T_D^F=[t_s,t_f]$ and it is required that the total consumption over a time period is kept constant, this situation can be modeled using (23).

3. Mixed-Integer Linear Programming (MILP) Model

The model provided in the previous section is nonlinear due to the products of binary variables *z* and continuous variables δ in constraints (4) and (14). However, it is possible to replace these nonlinear constraints with the following sets of exact equivalent mixed-integer linear constraints:

$$-z_{l,t}P_l^{\max}\le P_{l,t}^L\le z_{l,t}P_l^{\max};\quad \forall l\in L,\forall t\in T \tag{27}$$

$$\frac{1}{x_l}(\delta_{b,t}-\delta_{b',t})-P_{l,t}^L+(1-z_{l,t})M_l\ge 0;\ \ \forall l\in L,\forall t\in T \tag{28}$$

$$\frac{1}{x_l}(\delta_{b,t}-\delta_{b',t})-P_{l,t}^L-(1-z_{l,t})M_l\le 0;\ \ \forall l\in L,\forall t\in T \tag{29}$$

Where *M* is a large enough positive constant [4]. For the sake of simplicity, the expressions are only written for the day-ahead stage. The working of equations (27)-(29) for this stage is explained below.

On the one hand, if the dispatchable line is in service, i.e., binary variables $z_{l,t}$ are equal to 1 then in such a case, equations (27)-(29) impose that $-P_l^{\max}\le P_{l,t}^L\le P_l^{\max}$ and $\frac{1}{x_l}(\delta_{b,t}-\delta_{b',t})-P_{l,t}^L=0$. Note that these equations are equivalent to constraints (3) and (8).

On the other hand, if the dispatchable line is out of service, i.e., binary variables $z_{l,t}$ are equal to 0, equations (27)-(29) impose that $P_{l,t}^L=0$ and $-M\le\frac{1}{x_l}(\delta_{b,t}-\delta_{b',t})-P_{l,t}^L\le M$. First, we impose that the power flow through transmission line is null. Second, we consider large enough bounds on the difference between the voltage angles at two buses that are not connected through the disjunctive parameter *M*.

Using the linearization procedure described above, it is possible to reformulate the problem of co-optimization of transmission topology and generation dispatch as in the MILP problem below:

$$\text{Objective}:\ (1) \tag{30}$$

$$\text{Constraints } (2),\ (6),\ (7),\ (9)\text{-}(11) \tag{31}$$

$$\text{Constraints } (5),(27)-(29) \tag{32}$$

$$\text{Constraints } (12),(16)-(24),(26) \tag{33}$$

$$-z_{l,s,t}P_l^{\max}\le P_{l,s,t}^L\le z_{l,st}P_l^{\max};\forall l\in L,\forall \mathrm{s}\in \mathrm{S},\forall t\in T \tag{34}$$

$$\begin{aligned}&\frac{1}{x_l}(\delta_{b,s,t}-\delta_{b',s,t})-P_{l,s,t}^L+(1-z_{l,s,t})M_l\ge 0;\\&\forall l\in L,\forall \mathrm{s}\in \mathrm{S},\forall t\in T\end{aligned} \tag{35}$$

$$\begin{aligned}&\frac{1}{x_l}(\delta_{b,s,t}-\delta_{b',s,t})-P_{l,s,t}^L-(1-z_{l,s,t})M_l\le 0;\\&\forall l\in L,\forall \mathrm{s}\in \mathrm{S},\forall t\in T\end{aligned} \tag{36}$$

The optimization model above is solved using CPLEX 12.2.1 [18] called from GAMS environment [19].

After the co-optimization problem of generation dispatch and transmission switching is solved, the integer variables are frozen, the optimal solution for the scheduling and dispatch problem will be reduced to a Linear Programming (LP) problem in which market clearing quantities and locational marginal prices can be determined.

Locational marginal prices (LMP) for energy at bus *b* can be expressed as [6]:

$$LMP_b=LMP_E-LF_b.LMP_E+\sum_l SF_{l-b}.\mu_l \tag{37}$$

The three terms in the above LMP equation could be interpreted as the three components of LMP, namely energy, loss and congestion, respectively.

4. Results and discussions

In this section, the co-optimization model of network topology and generation dispatch considering demand response in combination with the uncertainty of renewable energy sources, which is based on two-stage stochastic model in the day-ahead markets is performed on the modified 5-bus system [20].

Regarding the computational complexity of the model for this modified 5-bus system, the number of continuous variables is 6384 and the number of binary variables is 1848.

4.1. System description

The test system is shown in Figure 1. There are seven transmission lines, three conventional generators, one wind farm and three demands in this system. Total peak demand of system in the base case is 950 MW distributed on buses B, C and D as 216.67, 316.67 and 416.66 MW, respectively.

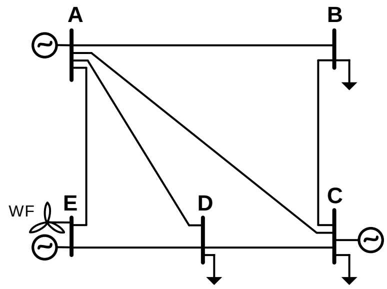

Figure 1. *One-line diagram of a 5-bus system*

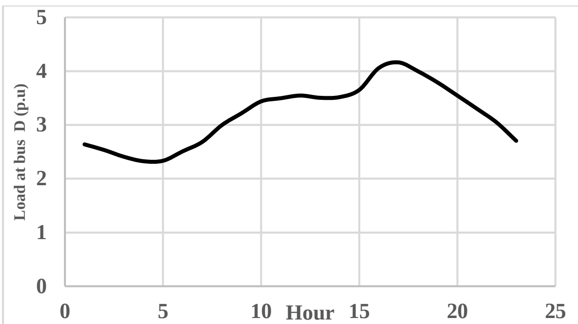

Figure 2. *Daily load curve at bus D of the base case*

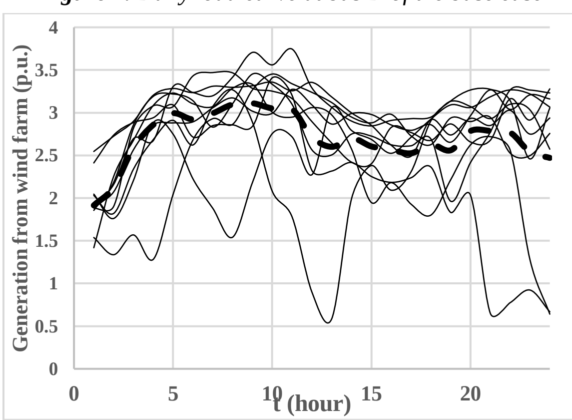

Figure 3. *Initial forecast and 10 scenarios for wind power generation at bus E*

The daily load curve of the base case at bus D is depicted in Figure 2. It is assumed that the daily load curve of three demands is the same. Moreover, scenarios of the wind power generation are used as input to the stochastic programming approach to solve the proposed model. The set of these scenarios can be obtained by means of time series models [21], [22]. In this paper, we also assume 10 different scenarios for the wind power generation at bus E as shown in Figure 3, in which each solid line represents of maximum power produced by the wind farm in one scenario and dashed line represents the mean value of scenarios. This mean value is equal to the initial wind power forecasted in the first stage within considered 95% confidence interval.

The regulation cost of generating units at bus A is assumed to be $C_{A,t}^{R+} = 15\,\$/\mathrm{MWh} > C_{A,t}^{R-} = 12\,\$/\mathrm{MWh}$. The cost of the demand response is considered to be $C_{d,t}^{D+} = C_{d,t}^{D-} = 5\,\$/\mathrm{MWh}$.

4.2. Results from optimal transmission switching (OTS)

In this subsection, four representative operating points (cases 1-4) at different system load levels are chosen to investigate the economic savings due to optimal transmission switching. Assuming all 7 lines are switchable and *J* is set to 3. Moreover, flexible demands are at buses B and D and the demand flexibility is set to 10%. The objective costs for cases with and without considering transmission switching are listed in Table 1.

Table 1. *Comparison of the objective costs with and without considering transmission switching*

Total peak demand (MW)	Objective ($)	
	w/o OTS	w/ OTS
950	335591.6	332885.7
1140	388199.2	380768.9
1330	455319.3	444017.8
1615	Infeasible	647047.9

It can be seen from Table 1 that when the maximum total system demand is 1615 MW (case 4), the solution of problem without optimal transmission switching is infeasible. However, with considering transmission switching, the problem returns a feasible solution. Additionally, the total cost with OTS is lower than that of without OTS. Particularly, if the system peak demand is 1330 MW, the total cost savings due to TS is 11301.5 $, which is approximately 2.55 % of the total cost.

Table 2. *Switched lines in 24 time periods (1 – in service, 0 – out of service)*

Line	Periods (hours)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
A-B	1	0	1	1	1	1	1	1	1	0	1	1	0	1	1	1	1	1	1	1	0	1	1	0
A-C	1	1	1	1	1	0	1	1	1	1	1	1	1	1	1	1	0	0	0	1	1	1	1	1
A-D	1	1	1	0	0	0	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	1	1
A-E	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
B-C	0	1	0	1	0	1	0	0	0	1	0	0	1	0	0	0	0	0	0	0	1	0	0	1
C-D	0	0	0	1	1	1	1	0	1	0	1	0	0	0	1	0	1	1	1	0	0	0	0	0
D-E	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 2 shows the switchable lines are out of service in the 24 time periods when the maximum demand of system is equal to 1330 MW. From Table 2, it can be observed that the number of open lines vary according to the time period. While there is one open line in the 7th hour, two lines are switched off in the first hour.

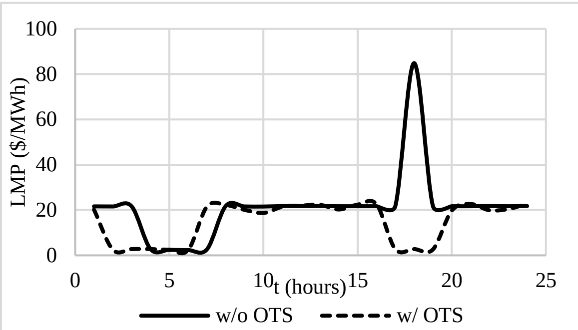

Figure 4. *LMP at bus A with and without OTS*

Figure 4 depicts the change of marginal prices at node A in the 24 time periods. A notable remark is that LMP at bus A with OTS is generally lower than that without OTS. This is because of the fact that transmission switching can enhance the flexibility of power networks; therefore, the congestion level in power systems is reduced.

4.3. Impact of the maximum number of open lines

In this subsection, the effects of the maximum number of open lines on both the simulation times are described. It is assumed that the system peak load is 1615 MW and three loads are inflexible. The results of computational times for various values of *J* using a personal computer with Intel core-i5 processor and 8GB of RAM are illustrated in Table 3. By controlling the values of *J* below a certain value, it is practical to solve the problem in a reasonable time frame.

Table 3. *Solution times vary with J*

J	1	2	3	4	5
Time (s)	51.74	986.69	997.22	992.79	985.82

5. Conclusion

In this paper, we presented the two-stage stochastic programming approach to resolve a multi-period optimal power flow problem, which simultaneously optimize network topology and power output of generators. This proposed model integrates flexible demands and uncertain renewables. The demand flexibility can come from any bus of the network. Numerical results show that the uncertainty of renewables can be optimally dealt with using flexibilities from both demand side and generation side. In addition, there are substantial improvements in system dispatch cost by optimizing the transmission network and switching lines in and out based on system conditions. It is important to note that optimal transmission switching may likely affect locational marginal prices. Further studies of the methods for selection of transmission line candidates with the aim of computing within the required time frame are desirable.

NOMENCLATURE

The main mathematical symbols used throughout this paper are classified below.

Parameters:

x_l	Reactance of line l
$P^W_{w,s,t}$	Generation available under scenario by the *w*th wind power unit in hour *t*
$P^{W\max}_{w,t}$	Initial power generation available from wind power unit *w* in hour *t*
$P^D_{d,t}$	Power consumed by the *d*th load in hour *t*
R^U_g	Ramp-up limit of the *i*th unit
R^D_g	Ramp-down limit of the *i*th unit
$P^{\max}_l$	Maximum power flow capacity of line l
P^{G+}_g	Upper bound on the power output of the *g*th producer
P^{G-}_g	Lower bound on the power output of the *g*th producer
$R^+_{g,t}, R^-_{g,t}$	Permissible upward and downward regulation of the generator *g* in the time period *t*, respectively
$F^+_{d,t}, F^-_{d,t}$	Maximum, minimum flexibility of demand *d* in hour *t*
$C^{R+}_{g,t}, C^{R-}_{g,t}$	Upward and downward regulation cost for generator *g*
$C^{D+}_{d,t}, C^{D-}_{d,t}$	Cost related to increasing, decreasing demand *d* in the time period *t*
$C^W_{w,t}$	Cost of the *w*th renewable generation spillage in hour *t*
$\lambda_{w,s}$	Probability of scenario *s*
J	Maximum number of open transmission lines
$f\left(P^G_{g,t}\right)$	Cost function of generator *g* in the time period *t*
N	Number of nodes

Variables:

$P^G_{g,t}$	Power output corresponding to the *g*th unit in hour *t*
$\Delta P^G_{g,s,t}$	Second stage recourse variable for power output of generator *g* in hour *t*
$\Delta P^{G+}_{g,s,t}, \Delta P^{G-}_{g,s,t}$	Upward and downward regulation of power output of generator *g* under scenario *s* in hour *t*
$P^W_{w,t}$	Power output corresponding to the *w*th renewable generator in hour *t*
$P^{spill}_{w,s,t}$	Spilled real power of the *w*th renewable generator under scenario *s* in hour *t*
$\Delta P^D_{d,s,t}$	Change in power consumed at bus *d* in hour *t*
$P^L_{l,t}$	Power flow in line *l* in hour *t* in the first stage
$P^L_{l,s,t}$	Power flow in line *l* under scenario *s* in hour *t* in the second stage
$\delta_{b,t}$	Voltage phase angle at bus *b* in hour *t* in first stage
$\delta_{b,s,t}$	Voltage phase angle at bus *b* in hour *t* in second stage
LF_b	Loss factor at bus *b*
SF_{l-b}	Sensitivity of branch power flow *l* with respect to injected power *b*
μ_l	Shadow price of transmission constraint on line *l*
$z_{l,t}$	Binary variables: $z_{l,t} = 1$ if the *l* th dispatchable line is in service in hour *t*; $z_{l,t} = 0$ if not
$z_{l,t,s}$	Binary variables: $z_{l,t,s} = 1$ if the *l* th dispatchable line is in service under scenario *s* in hour *t*; $z_{l,t,s} = 0$ if not

Sets:

G	Generator, indexed by g
L	Lines, indexed by l
W	Renewable generators, indexed by w
D	Demands, indexed by d
D_o	Flexible demands
S	Scenarios, indexed by s
T	Discrete set of time intervals, indexed by t
L_1	Transmission lines whose "to" side is connected to bus b
L_2	Transmission lines whose "from" side is connected to bus b

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