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Improving Wind Power Utilization in System Dispatch Considering Output and Ramp Rate Dependent Generator Costs

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ABSTRACT. Making use of the steam heat storage in thermal generators enables them to operate in a "fast mode" to ramp up or down faster than regular, so as to better catch up with the fluctuations of wind power to improve system wind utilization. In such fast mode, generators have output dependent ramp rates and, distinguished from regular units, output and ramp rate dependent coal consumption costs. These fast generators cannot be properly described by using existing economic dispatch models, where generators usually have output dependent cost functions and constant ramp rate limits. This paper presents a new formulation and solution methodology of dynamic economic dispatch for wind-thermal power systems, to take into account ramping capabilities and costs of generators in their fast mode. In our model, the objective is to minimize a two-variable quadratic generator cost function depending on both output levels and ramp rates, and generator ramp rate limits are output dependent piece-wise linear functions. The model is solved by using existing quadratic programming methods, and is demonstrated by using numerical examples on the IEEE 30-bus system containing two 600MW thermal units with practical data. Results show that by using our model, unit ramping capabilities are better utilized in system dispatch to substantially save curtailed wind energy, and total generator costs are reduced.

Keywords: economic dispatch, generator cost, MW-dependent ramp rate, quadratic programming, wind utilization

1. Introduction

Under the global situation of energy shortage, the role of renewable energy sources, such as wind energy, is getting more and more important in power systems because of their economical and environmental friendly features (Jouanne et al., 2005; IPCC, 2012; Liu et al., 2012). However, wind energy is fluctuating and intermittent in nature, and many recent efforts have been made by researchers to handle the challenges brought by wind to power system operations (Chen, 2008; Wang et al., 2008; Pappala et al., 2009; Milligan et al., 2009; Kabouris et al., 2010; Ding et al., 2010; Zhang et al., 2011; Zhu et al., 2011; Wang et al., 2011; Wang et al., 2012; Suo et al., 2013; Pozo et al., 2013; Hu et al., 2014; Li et al., 2016). In the past few years, the huge amount of wind curtailments becomes one of the key issues in the grid of China. For example, the total curtailed wind and solar energy reaches up to 39 billion kilowatt hours in the year 2015 (Shu et al., 2017), and considering the average residential electricity price as 0.5 RMB or 0.08 USD per kilo-watt hour, the potential economic loss is as much as 19.5 billion RMB or over 3 billion USD.

One major reason of wind curtailment is that traditional thermal units generally have low ramp rates. In China, for example, nearly 80% of power is supplied by thermal generators with ramp rate limits of roughly 1% to 2% of their rated capacity per minute. Concerns of grid operators are that if wind power changes drastically, thermal generators may not be able to ramp up or down fast enough to catch up with such changes. In this case, the grid may no longer be able to maintain power balance, then either security constraints of voltage or frequency may be violated or part of demand cannot be served.

One possible way to reduce wind curtailment is to operate some of the thermal generators by using flexible control techniques, so as to enhance their ramping capabilities to better catch up with the fluctuations of wind power (Liu et al., 2015). Requirements on thermal generator ramping have already been considered in the operations of many large power grids, such as those in the United States (Cochran et al., 2014) and in Germany (Schiffer, 2014). Ramp up or down capabilities of a thermal generator usually depend on its coal inputs, and its efficiency in converting coal to power. Recent publications (Wang et al., 2006; Yao et al., 2006; Xing, 2007; Wang et al., 2010; Yao et al., 2010; Wang, 2013; Liu et al., 2014; Wang et al., 2014b; Wang et al., 2015; Hu et al., 2015a; Hu et al., 2015b; Wang et al., 2016; Wang et al., 2017) have studied various fast ramping techniques for thermal units. As one of the key results, Wang et

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al. (2014b) presented a method to improve unit ramping capabilities through controlling cooling water flow, which usually keeps constant in regular operations. In Wang et al. (2014b), the unit is operated in a "fast mode" where the condenser pressure changes with the cooling water flow, so that the steam heat storage is relived or accumulated to make the tur-bine power output ramp up or down faster than regular. Other flexible control techniques for thermal units include condenser cold source throttling (Yao et al., 2006; Yao et al., 2010; Hu, 2015b), the extraction pressure regulating for heating units (Wang, 2013; Liu et al., 2014), optimal load dispatch at the plant level (Wang et al., 2006; Xing, 2007) and so on. With the increasing integration of renewable energy sources in future grids, the above flexible control techniques will gradually change the functions of coal-fired thermal generators from the “base load supliers” to the “peak load balancers”, so that the more economical, environmental friendly and renewable power can be better utilized.

While the above fast mode generators are helpful in system dispatch to improve wind power utilization, using heat storage requires additional coal consumption in controlling the cooling water pump. Therefore, generator costs in fast mode become higher than regular, and are dependent of not only the output levels of generators, but also their actual ramp rates. Also, ramp rate limits of fast mode generators are not constant, but are output dependent, in that different quantities of heat storage are available at different output levels. In existing economic dispatch models, generator costs are usually output dependent fuel costs, and unit ramp rate limits are usually constants indicating average ramp rates. A few results have been reported on system dispatch with output dependent ramp rates in, e.g., Rios-Zalapa et al. (2010); Hui et al. (2013); Xu et al. (2013); Song et al. (2014); Li et al. (2016), while impacts of unit heat storage on ramp rates were not considered, and ramp rate dependent generator costs have not been studied. Therefore, characteristics of such fast mode generators cannot be properly modeled in existing formulations of economic dispatch.

In this paper, we present a new formulation of economic dispatch for wind-thermal power systems considering output and ramp rate dependent costs of fast mode generators (Economic Dispatch with Fast Ramping Generators, ED-FRG). In our model to be presented in Section 3, the objective is to minimize a quadratic and positive definite generator cost function with variables of both unit outputs and ramp rates, instead of the output dependent costs in existing models. The ramp rates are also output dependent, with ramp up and down rate limits in one decision period being piece-wise linear functions of generation levels in the previous period. The cost and ramp rate limit functions are determined by the characteristics of a specific unit, and can be obtained offline through parameter fitting. Wind power forecasts and error distributions are assumed available, and constraints on wind power outputs are formulated as chance constraints, ensuring the dispatch solutions to be feasible with a high confidence probability. Besides, system-wide security constraints of power balance and transmission line limits are also considered. Decision interval of our model is set as one minute, because impacts of heat storage on fast ramping are typically effective within 0.5 to 1 minutes, but are rather weak within time scales of 5 to 15 minutes or longer.

The above formulation has a quadratic and positive definete two-variable objective function and linear constraints, and can be solved by existing quadratic programming methods similar to linear programming methods, e.g., the Simplex method (Luenberger, 2003). We present several numerical examples in Section 4 to demonstrate the effectiveness of our model. In Subsection 4.1, the cost and ramp rate limit functions for a 600 MW unit is obtained through parameter fitting in MATLAB, by using data from Wang et al. (2014b). Solution procedure of our model is implemented by using the optimization platform IBM ILOG CPLEX, and testing examples on a 3-bus system and the IEEE 30-bus system are presented in Subsections 4.2 and 4.3, respectively. Results show that compared with the existing model, our model is able to better make use of the ramping capabilities of fast mode generators to substantially save curtailed wind energy, and system generator costs are reduced as well.

2. Literature Review

A large amount of research efforts have been reported on wind energy integration into power grids, especially in the past 4 to 5 years. Wind power characteristics and its impacts on system operations have been discussed in, e.g., Milligan et al., (2009); Kabouris et al. (2010); Zhang et al. (2011); and Zhu et al. (2011). Various methods have been developed for the unit commitment and economic dispatch problems with wind power penetration in Chen (2008); Wang et al. (2008); Pappala et al. (2009); Ding et al. (2010); Wang et al. (2011); Wang et al., (2012); Pozo et al. (2013), including Direct Search Method (Chen, 2008), Benders Decomposition (Wang et al., 2008) and Particle Swarm Optimization (Pappala et al., 2009), etc. Uncertainties of wind power have been treated by using, e.g., scenario based methods (Wang et al., 2008; Pappala et al., 2009; Wang et al., 2011), chance constraints (Ding et al., 2010; Wang et al., 2012; Pozo et al., 2013), etc.

Generator ramping constraints are usually considered in the unit commitment problem with hourly decisions, while Giang (2003); Wang et al. (1993); Wang et al. (2000) included these constraints in the security constrained economic dispatch problem, and corresponding solution methodologies were presented. Wind power, however, was not considered in the above papers. Output dependent ramp rates, also called as “MW-dependent ramp rates”, for generators have been considered in a few recent conference papers (Rios-Zalapa et al., 2010; Hui et al., 2013; Xu et al., 2013; Song et al., 2014; Li et al., 2016) with the motivations of ensuring the efficiency and feasibility of energy dispatch (Rios-Zalapa et al., 2010), improving the performance of electricity markets (Hui et al., 2013; Xu et al., 2013) and maintaining accurate and efficient quantities of reserves in real-time markets (Song et al., 2014). Such ramp rate models are piece-wise constant functions of generator outputs, as implemented in ERCOT (Hui et al., 2013; Xu et al., 2013) and ISO-NE (Song et al., 2014) markets, while the impacts of unit heat usage on ramp rates and those of ramp rates on generator costs have not been considered.

Recent publications have reported various flexible control techniques to improve ramping capabilities of thermal generators. First, a condenser cooling water control system (CCWCS) was proposed in Wang et al. (2014b) to improve the load change capacity for wet cooled power plants. Continuous cooling water flow adjustments were performed to make use of the heat storage in the steam to achieve fast ramping, as demonstrated by a case study on a 600 MW unit. Second, the static and dynamic model of the condenser cold source throttling was formulated in Liu et al. (2015), and experimental study for a 330 MW units showed that its ramp rate reached up to 6% per minute of its rated capacity. An experimental study for the 900 MW supercritical units was presented in Yao et al. (2006) and Yao et al. (2010), and by using condense throttling control the ramp rate of the unit reached up to 5.3% per minute of its rated capacity. Third, the extraction pressure regulating of heating units can send the extraction steam to the turbine to generate extra output that would otherwise be used to generate heat. In Liu et al. (2014), load changing instructions of the heating unit were reconstructed and optimized by non-linear multi-scale decomposition of the AGC load instruction. In Wang (2013), ramp rates of heating units were improved to more than 5% per minute of their rated capacities by making use of their heat storage. Fourth, optimal load dispatch at the plant level can also help enhance the flexibility of generator operations (Wang et al., 2006; Xing, 2007).

The objective of system economic dispatch is usually to minimize the total operating costs of all units. The major component of unit operating cost is the fuel cost, which is generally modeled as a quadratic polynomial function of unit output levels (Kothari and Nagrath, 2003). By considering valve point effects in, e.g., Park et al. (2005), Wang et al. (2014a), Zhan et al. (2015a) and Zhan et al. (2015b), generator cost functions become non-smooth while still depending solely on unit output levels. The coal consumption rates during unsteady processes of generators were shown to be affected by unit heat storage in Guo et al., (2007), while costs of using heat storage to improve unit ramping capabilities were not studied.

3. Mathematical Formulation of ED-FRG

In this section, formulation of the Economic Dispatch for systems containing Fast Ramping Generators (ED-FRG) is presented. Subsection 3.1 describes the problem. Subsection 3.2 presents the mathematical formulation, including the two-variable generation cost function, the unit ramp rate constraints and other constraints of the problem.

3.1. Problem Description

Consider a system with N buses, G thermal generators, W wind farms and L transmission lines. For simplicity, only steady state DC load flow is considered. Each thermal generator has an integer index g, $g = 1, \ldots, G$, and its maximum and minimum generation levels are, $p_{g,max}$ and $p_{g,min}$, respectively. Each wind farm is indexed by an integer $w = 1, \ldots, W$. For each line l ($l = 1, \ldots, L$), transmission capacity upper and lower bounds are $F_{l,max}$ and $F_{l,min}$, respectively.

For the above system, the dynamic economic dispatch problem is considered for a given time horizon T, and $t = 1, \ldots, T$ are the decision periods. Assume that in each period t, demand forecast $d_n(t)$ is available for each bus n, and wind power forecast $p_{w,f}(t)$ is available for each wind farm w. Wind power forecast error, $e^r_{w,f}(t)$, is assumed to be a random variable observing a Normal Distribution $N(0, \sigma^2_w(t))$, i.e., with the mean of 0 and the standard deviation of $\sigma_w(t)$. The problem is to decide, in each period t, the thermal generation levels $p_g(t)$ ($g = 1, \ldots, G$) and wind output levels $p_w(t)$ ($w = 1, \ldots, W$), to minimize the total generator costs while satisfying system-wide security constraints. Mathematical formulation of the problem is presented as follows.

3.2. Mathematical Formulation

3.2.1. Two-variable Generator Cost Function

Objective function of the problem is to minimize the total generator costs over the entire time horizon. Since wind farms are assumed to have no generator costs, only thermal generator costs are considered, as represented by the following two-variable quadratic function:

$$\min_{p_g, p_w} \sum_{t=1}^{T} \sum_{g=1}^{G} \left(c_g^1 p_g^2(t) + c_g^2 \Delta_g^2(t) + c_g^3 p_g(t) \Delta_g(t) + c_g^4 p_g(t) + c_g^5 \Delta_g(t) + c_g^6 \right) \tag{1}$$

where $c_g^1, \ldots, c_g^6$ are coefficients of a positive definite quadratic function, and

$$\Delta_g(t) = p_g(t) - p_g(t-1),\ g = 1, \cdots, G;\ t = 1, \cdots, T \tag{2}$$

is the ramp rate in decision period t ($t = 1, \ldots, T$).

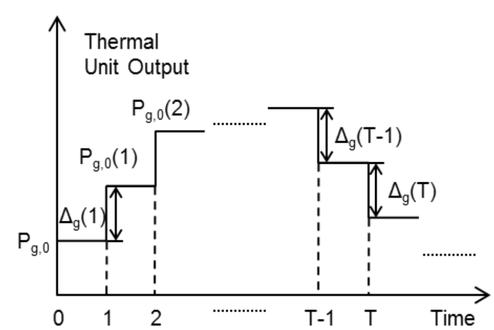

Figure 1. Variables in corresponding decision periods of the problem.

The two-variable cost function in (1) is different from those of existing economic dispatch models, where a quadratic fuel cost function depending on unit output levels is used. The reason for fuel cost function to be quadratic is that, according to the physical characteristics of thermal generators, the incremental fuel cost is monotonically increasing with respect to unit output levels. Since ramp rate is derivative of unit output levels, we straightforwardly assume that generator costs are also quadratic of unit ramp rates, thus leading to the two-variable quadratic objective function (1).

Based on (1), in the period from time t-1 to t, costs of generator g depend both on on $p_g(t)$, the output level at time t,and $\Delta_g(t)$, the ramp rate in the period. It is mandatory that function (1) is positive definite, in that generator costs should always be positive given any output level and ramp rate. Parameters of the two-variable cost function for a specific unit can be fitted by using its ramp rate and coal consumption data, as to be illustrated by an example on a 600 MW unit in Subsection 4.1.

3.2.2. Constraints on Thermal Generators

Thermal generators need to observe constraints on output ranges and ramp rates. First, output levels of each thermal generator g should be within the corresponding lower and upper bounds at any time t:

$$p_{g,min} \le p_g(t) \le p_{g,max}, g = 1, \cdots, G; t = 1, \cdots, T \quad (3)$$

Second, the ramp rate of unit g in period t, $\Delta_g(t)$, needs to be within the ramp up and down rate limits of the unit, i.e.,

$$\Delta_g^-\left(p_g(t)\right) \le \Delta_g(t) \le \Delta_g^+\left(p_g(t)\right), g = 1, \cdots, G; t = 1, \cdots, T \quad (4)$$

where $\Delta_g^-(\cdot)$ and $\Delta_g^+(\cdot)$ are piece-wise linear functions with s^- and s^+ segments, respectively, i.e.,

$$\Delta_g^-(x) = \begin{cases} u_{g,1}^- x + v_{g,1}^-, p_{g,min} \le x \le p_{g,1}^- \\ u_{g,2}^- x + v_{g,2}^-, p_{g,1}^- \le x \le p_{g,2}^- \\ \vdots \\ u_{g,s^-}^- x + v_{g,s^-}^-, p_{g,s^--1}^- \le x \le p_{g,max} \end{cases} \quad (5)$$

$$\Delta_g^+(x) = \begin{cases} u_{g,1}^+ x + v_{g,1}^+, p_{g,min} \le x \le p_{g,1}^+ \\ u_{g,2}^+ x + v_{g,2}^+, p_{g,1}^+ \le x \le p_{g,2}^+ \\ \vdots \\ u_{g,s^+}^+ x + v_{g,s^+}^+, p_{g,s^+-1}^+ \le x \le p_{g,max} \end{cases} \quad (6)$$

While in existing models the ramp rate limits Δ_g^- and Δ_+ are usually constants, in our model they are output dependent functions. In this way, constraint (4) is applicable to fast mode generators whose ramping capabilities achieved by using heat storage vary with output levels. Parameter fitting of functions $\Delta_g^-(\cdot)$ and $\Delta_g^+(\cdot)$ is to be illustrated by an example on a 600 MW unit in Section 4.1.

3.2.3. Constraints on Wind Farms

We model wind farms as stochastic power generators by using chance constraints. With a high probability α, output level of each wind farm w at time t should be between zero and the actual available wind power, which is sum of the forecasted wind power and its random forecast error:

$$Pr\left\{0 \le p_w(t) \le p_{w,f}(t) + e_{w,f}^r(t)\right\} \ge \alpha, w = 1, \cdots, W; t = 1, \cdots, T \quad (7)$$

Constraint (7) is modeled as a chance constraint to avoid the dispatch solutions to be over-conservative, in that deficiencies of wind power occurred with a low probability 1-α can almost always be covered by system reserves. It can be proved (Liu et al., 2003) that (7) is equivalent to the deterministic form:

$$0 \le p_w(t) \le p_{w,f}(t) + \phi_{w,f,t}^{-1}(1-\alpha), w = 1, \cdots, W; t = 1, \cdots T \quad (8)$$

where $\phi_{w,f,t}^{-1}(\cdot)$ is the inverse of the probability distribution function (PDF) of random variable $e_{w,f}^r(t)$. Taking $\alpha = 0.98$, and given the Normal Distribution $N(0, \sigma_w^2(t))$ of the forecast error $e_{w,f}^r(t)$, it is obtained that:

$$\phi_{w,f,t}^{-1}(1-0.98) \approx -2\sigma_w(t) \quad (9)$$

and (7) is thus converted to:

$$0 \le p_w(t) \le p_{w,f}(t) - 2\sigma_w(t), w = 1, \cdots, W; t = 1, \cdots, T \quad (10)$$

3.2.4. System-wide Security Constraints

The problem has two system-wide security constraints. One is that the power balance between supply and demand needs to be maintained for the entire system at any time t, i.e.,

$$\sum_{g=1}^{G} p_g(t) + \sum_{w=1}^{W} p_w(t) = \sum_{n=1}^{N} d_n(t), g = 1, \cdots, G; w = 1, \cdots, W; \\ t = 1, \cdots, T \quad (11)$$

and the other is that transmission capacity limits need to be observed for each line, i.e.,

$$F_{l.min} \le \sum_{n=1}^{N} \varphi(n,l)\left(\sum_{I_G(g)=n} p_g(t) + \sum_{I_W(w)=n} p_w(t) - d_n(t)\right) \le F_{l,max}, \\ l = 1, \cdots, L; \ t = 1, \cdots, T \quad (12)$$

where $\varphi(n, l)$ is the generation shift factor (Wood, 1996) between bus n and line l, and $I_G(g)$ and $I_W(w)$ are the numbers of buses where thermal generator g and wind farm w are located, respectively.

The above objective Function (1) and Constraints (2) to (6) and (10) to (12) constitute the Economic Dispatch model with Fast Ramping Generators (ED-FRG). It contains a quadratic positive definite objective and linear constraints, and can be routinely solved by using existing quadratic programming techniques, which are similar to linear programming methods such as the Simplex method (Luenberger, 2003). Solution procedure of the above problem will be tested in the next section.

4. Numerical Example and Analyses

In this section, three numerical examples are presented. Subsection 4.1 presents an example of parameter fitting by using MATLAB for the two-variable generator cost and ramp rate limit functions of a 600 MW generator. Subsection 4.2 presents an illustrative example on a 3-bus system to demonstrate the effectiveness of our model. In Subsection 4.3, the IEEE 30-bus system (UW, 1999) is used to analyze the performances and computational requirements of our model for larger systems. The quadratic programming problems in the tests are solved by using IBM ILOG CPLEX version 12.4 on a personal computer with Pentium(R) Dual-Core E5300 2.60 GHz CPU and 2.00 GB memory.

4.1. Parameter Fitting for a 600 MW Unit

In this example, a 600 MW unit of Pan-Shan Power Plant in Jixian, Tianjin, China is studied. Maximum and minimum output levels of the unit are 600 MW and 270 MW, respectively. Output and coal consumption data of the unit are provided in Wang et al. (2014b), and part of the data is listed in Table 1 and Table 2.

First, ramp rate limit functions of the unit are fitted. At seven different output levels as in column 1 of Table 1, the maxi-mum and minimum outputs achieved in one minute by using heat storage are given in columns 2 and 3. Based on columns 1 to 3, the ramp up and down rate limits at various output levels can then be calculated, as in columns 4 and 5.

For the ramp up rate limit function, $\Delta_g^+(\cdot)$, data points are taken from columns 1 and 4 of Table 1, as shown in Figure 2. It can be seen that ramp up rate limits increase with output levels with high linearity. By using MATLAB, the fitting linear function is obtained as:

$$\Delta_g^+(p_g) = 0.026p_g - 3.75,\ 270 \le p_g \le 600 \tag{13}$$

and its fitting goodness index, R-square (Fei, 2004), is 0.987[1].

On the other hand, data points of the ramp down rate limit function $\Delta_g^-(\cdot)$ are taken from columns 1 and 5 of Table 1, as shown in Figure 3. It can be seen that with the increase of output levels, ramp down rate limits first decrease then increase with an obvious turning point. Therefore, a piece-wise linear function form is used to fit $\Delta_g^-(\cdot)$. The three points on the left are used to fit the decreasing part linear function, the five points on the right are used to fit the increasing part, and intersection of the two parts fixes the turning point. The fitting piece-wise linear function is:

$$\Delta_g^-(p_g) = \begin{cases} 19.48 - 0.14p_g,\ 270 \le p_g < 416.96 \\ 0.026p_g - 50.64,\ 416.96 \le p_g \le 600 \end{cases} \tag{14}$$

where the turning point is p_g= 416.96 MW, and its fitting goodness index, R-square, is 0.997 (R-square is an index within [0, 1] to describe the goodness of fitting, and a larger R-square indicates a better fitting.).

Table 1. Ramp Rate Limits of the 600 MW Unit

	1	2	3	4	5
Output ratio	Output p_g (MW)	Max p_g in one minute (MW)	Min p_g in one minute (MW)	Ramp up rate limit (MW/min)	Ramp down rate limit (MW/min)
1	583.66	595.31	548.37	11.65	-35.29
0.9	527.43	537.19	490.03	9.76	-37.40
0.8	470.78	478.87	431.91	8.09	-38.87
0.75	442.30	449.64	402.96	7.34	-39.34
0.7	413.72	420.37	374.11	6.65	-39.61
0.6	356.30	361.69	325.32	5.39	-30.98
0.5	298.53	302.83	275.33	4.30	-23.20

Table 2. Coal Consumption Rates b_g (g/kWh) and Generator Costs (¥) of the 600 MW Unit

Unit mode	In regular mode		At ramp up rate limit		At ramp down rate limit	
	1	2	3	4	5	6
Output (MW)	b_g	Cost	b_g	Cost	b_g	Cost
583.66	322	1628.80	322.70	1632.34	343.08	1735.43
527.43	323	1476.45	323.53	1478.88	348.19	1591.60
470.78	326	1330.11	326.39	1331.70	356.06	1452.76
442.30	330	1264.98	330.84	1268.20	362.12	1388.10
413.72	333	1194.00	332.34	1191.63	369.41	1324.55
356.30	338	1043.72	338.48	1045.20	370.68	1144.64
298.53	341	882.26	342.91	887.20	369.86	956.92

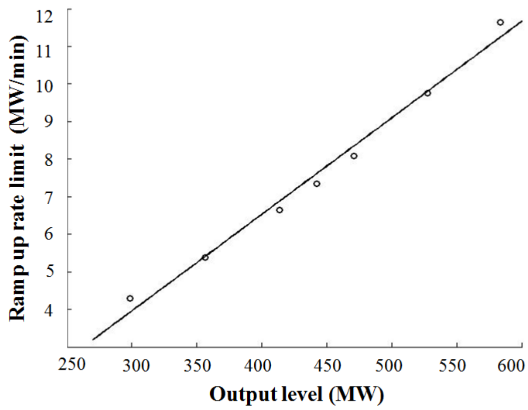

Figure 2. Fitting of the ramp up rate limit function.

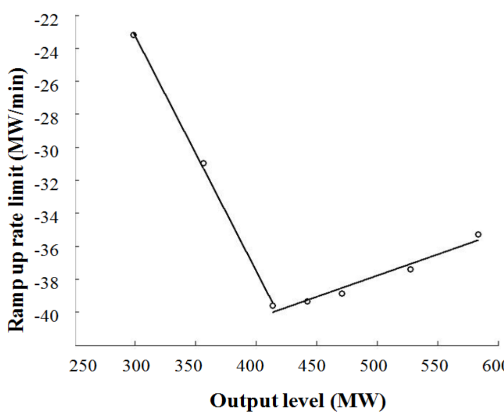

Figure 3. Fitting of the ramp down rate limit function.

Second, the two-variable generator cost function is fitted. The coal consumption rate, b_g, from Wang et al. (2014b) are listed in Table 2 for seven output levels, where column 1 lists the coal consumption rates of the unit in regular mode, and columns 3 and 5 list those of operating at ramp up and down rate limits in fast mode. For a single decision period with output level p_g, a basic relationship between the coal consumption rate b_g and the generator cost C is that:

$$C(p_g) = p_b b_g p_g D \tag{15}$$

where p_b is the coal price and D is the length of the period. Taking p_b as ¥520/100 kg according to China Energy (2015), and D = 1 minute = 1/60 hour, the coal consumption rates can be converted to period-wise generator costs, as given in columns 2, 4 and 6 in Table 2. These generator cost values at various output levels are used to fit the two-variable generator cost function as follows.

At each given output level, four data points of the cost function can be obtained. For example, the corresponding data points for p_g = 583.66 MW are shown in Figure 4, including cost C_1 at the ramp down rate limit in fast mode (-35.29 MW/min), C_2 at the ramp down rate limit in regular mode (-6 MW/min), C_3 at the ramp up rate limit in regular mode (3 MW/min), and C_4 at the ramp up rate limit in fast mode (11.65 MW/min). For seven different output levels, altogether 28 data points are available in a three dimensional space. By using a two-variable quadratic fitting function in MATLAB, the resulting cost function is:

$$\begin{aligned} &C_g(p_g,\Delta_g) = 0.000029 p_g^2 + 0.0023 p_g \Delta_g + 0.078 \Delta_g^2 + 2.55 p_g \\ &-1.42\Delta_g + 128 \\ &270 \le p_g \le 600;\ \Delta_g^+(p_g) \le \Delta_g \le \Delta_g^-(p_g) \end{aligned} \tag{16}$$

and its fitting R-square is 0.999. Function (16) is a positive definite quadratic function, and is plotted as a three dimensional surface shown in Figure 5, with the domain of the function indicated by the solid segments in the $p_g \sim \Delta_g$ plane.

As a comparison with the existing model, the regular output-based generator cost function of the unit is also obtained by using the data in column 2 of Table 2 as:

$$C_g(p_g) = 0.00034 p_g^2 + 2.23 p_g + 208.1,\ 270 \le p_g \le 600 \tag{17}$$

and the constant ramp up and down rate limits are set as 3 MW/min and -6 MW/min, respectively.

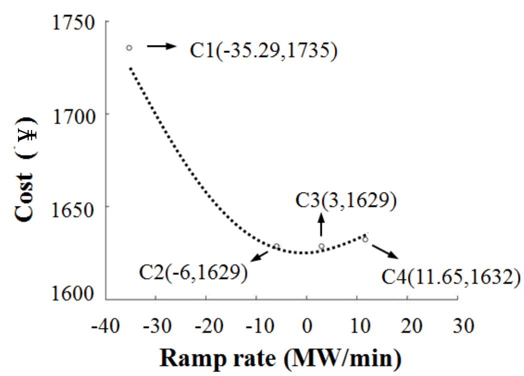

Figure 4. Function of generator cost versus ramp rate at pg = 583.66 MW.

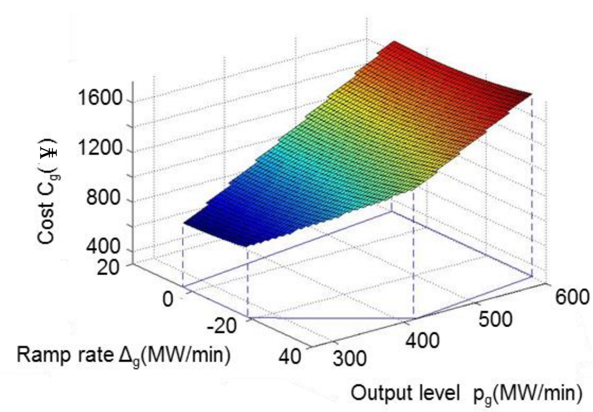

Figure 5. Two-variable generator cost function of the 600 MW unit.

By comparing the cost Functions (16) and (17), it is clear that in terms of form, (16) extends the domain of (17) from a one dimensional range of p_g to a two dimensional zone of (p_g, Δ_g). A set of values are calculated for (16) and (17) as listed in Table 3. It can be seen that by setting $\Delta_g = 0$, costs obtained by (16) in row 1 are very close to those obtained by (17) in row 2. In rows 3 and 4, similarly, costs obtained by (16) with $\Delta_g = 0$ are also close to those obtained by (17) in row 1, with the differences below 1%. However, if the unit is in fast mode with $\Delta_g > 0$, costs obtained by (16) become substantially different from those obtained by (17). At $p_g = 583.66$ MW, for example, the cost function (16) degenerates to one of Δ_g as:

$$C_g(583.66, \Delta_g) = 0.078\Delta_g^2 - 0.08\Delta_g + 1626.21, -35.29 \leq \Delta_g \leq 11.65 \tag{18}$$

which is a parabola as shown by the dotted curve in Figure 4. Similar relationships of $C_g \sim \Delta_g$ can be derived at all output levels. It is also shown in Table 3 that the costs at ramp up and down rate limits in fast mode in rows 5 and 6 are larger than those at regular ramp up and down rate limits in rows 3 and 4. This demonstrates that the two-variable cost function (16) has good compatibility with the regular cost function (17), while effectively reflects the additional generator costs to achieve large ramp rates in fast mode.

4.2. A 3-bus Example

In this section, an illustrative example on a 3-bus system is presented to demonstrate the effectiveness of our model. The system contains a thermal unit at bus 1, a wind farm at bus 2 and demand at bus 3, as shown in Figure 6. The thermal generator has the identical ramp rate limit and cost functions as obtained in Subsection 4.1, with the initial output level of 552 MW. The wind farm consists of 200 wind turbines, each with rated output of 1.5 MW, leading to the total rated capacity of 300 MW. Four different sets of wind power forecast data are taken from Xunfeng Wind Farm at Chengde, Hebei Province, China, in four different hours on February 25, 2013. Demand is assumed to fluctuate every minute following a set of load data collected from Jixian, Tianjin, China, on October 28, 2009, with the maximum demand of 800 MW. For all lines, the reactances are 1, and transmission capacity limits are -600 MW to 600 MW. As a comparison, the existing dispatch model is also tested, with cost Function (17), the ramp up rate limit 3MW /min and the ramp down rate limit -6MW/min.

Economic dispatch for the above 3-bus system is solved with the decision horizon of one hour, and the decision interval of one minute. In four testing scenarios with different wind power forecasts and for both the ED-FRG model and the existing model, the quantities of curtailed wind energy in terms of kWh are given in Table 4, and the generator costs are given in Table 5. It can be seen that the ED-FRG model outperforms the existing one in all testing scenarios, with more than 50% savings of curtailed wind energy and lower generator costs. This demonstrates that by using our model, ramping capabilities of fast mode units can be effectively used to reduce wind curtailments in the dispatch. Moreover, despite of the relatively high coal consumption rates in fast mode, the overall generator costs are down, because more wind power is utilized to serve the demand and thermal generation levels are reduced.

For test scenario 1, output curves of the thermal unit by using both the ED-FRG model and the existing one are shown in Figure 7, and the corresponding wind power output curves are shown in Figure 8. The two figures show that by using the ED-FRG model, ramping capabilities of the thermal unit can be better made use of to catch up with the wind power fluctuations than in the existing model, so that system wind utilization is improved.

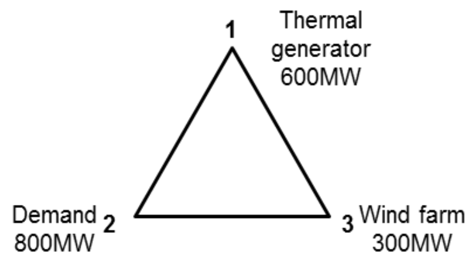

Figure 6. The 3-bus system to be studied.

4.3. The IEEE 30-bus Example

In this section, the IEEE 30-bus system is used to analyze the performances and computational requirements of our model. The system is shown in Figure 9, and the system topology and line reactance are given in (UW, 1999). Two 600 MW thermal units locate at buses 1 and 2, both with identical ramp rate and cost functions as obtained in Subsection 4.1, and both with initial output level of 492 MW at $t = 0$. A wind farm with rated capacity of 600 MW at bus 13, and four sets of wind power forecasts are taken from Xunfeng Wind Farm at Chengde, Hebei Province, China, on February 25, 2013. The maximum total demand is 1500 MW, and demand at all buses fluctuates every minute following a set of load data collected from Jixian, Tianjin, China, on October 28, 2009, while proportions of demand among all buses are kept as given in UW, (1999). Transmission capacity limits are -450 MW to 450 MW for line (1, 2), and -200 MW to 200 MW for all other lines. For comparison, the existing ED model is also tested, with the cost function of both thermal units as in (15) and ramp up and down rate limits of the thermal units as 3MW/min and -6MW/min., respectively.

Economic dispatch is solved for the above IEEE 30-bus system, with the decision horizon of one hour and the decision interval of one minute. Four scenarios are tested with different wind power forecasts. Testing results of curtailed wind energy and generator costs are given in Table 6 and Table 7. It can be seen that compared with the existing ED model, the ED-FRG model saves more than 50% of curtailed wind energy. Meanwhile, generator costs of the ED-FRG model are lower than those of the existing model. Table7 also gives the CPU times of the solution procedure in two cases. It can be seen that computational requirements to solve the ED-FRG model are a bit

Table 3. Regular and Two-variable Generator Costs (¥)

Row No.	Output level p_g(MW)		583.66	527.43	470.78	413.72	356.30
1	Regular cost by (17)		1626.89	1480.05	1334.30	1189.72	1046.47
2	$\Delta = 0$ MW/min	Two-variable cost by (16)	1624.36	1479.34	1333.44	1186.66	1039.14
		Difference with regular cost	0.16%	0.05%	0.06%	0.26%	0.70%
3	$\Delta = 3$ MW/min	Two-variable cost by (16)	1624.82	1479.42	1333.13	1185.95	1038.04
		Difference with regular cost	0.13%	0.04%	0.09%	0.32%	0.81%
4	$\Delta = -6$ MW/min	Two-variable cost by (16)	1627.61	1483.37	1338.24	1192.25	1045.52
		Difference with regular cost	0.04%	0.22%	0.30%	0.21%	0.09%
5	$\Delta = \Delta_g^+(P)$	Two-variable cost by (16)	1633.97	1484.71	1335.79	1187.28	1038.16
6	$\Delta = \Delta_g^-(P)$	Two-variable cost by (16)	1723.57	1595.43	1463.56	1326.71	1132.04

Table 4. Curtailed Wind Energy in the 3-bus Example (kWh)

Test scenario	1	2	3	4
Thermal unit in regular mode	9535.60	4959.86	8095.29	7385.46
Thermal unit in fast mode	3590.94	1535.03	2539.79	3000.96
Percentage of savings	62.34%	69.05%	68.63%	59.37%

Table 5. Generator Costs in the 3-bus Example (¥)

Test scenario	1	2	3	4
Thermal unit in regular mode	90619.64	88899.93	90878.98	89238.61
Thermal unit in fast mode	90067.25	88616.47	90380.57	88844.60

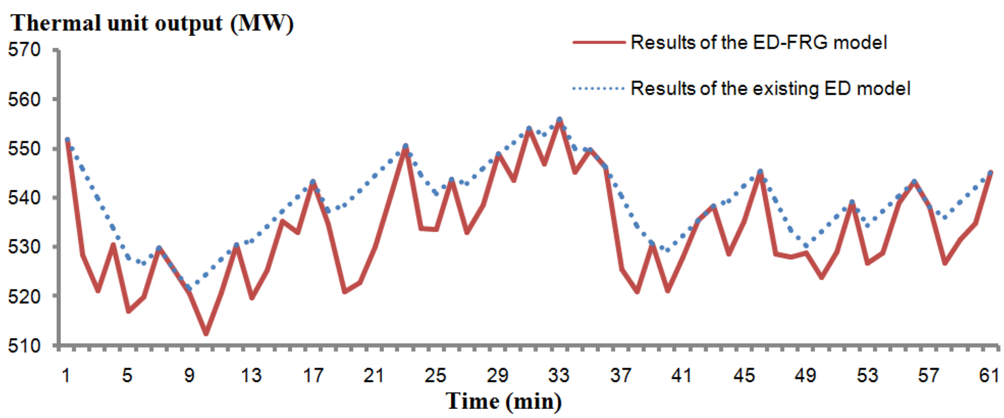

Figure 7. Thermal generation output curves in test scenario 1 of the 3-bus system.

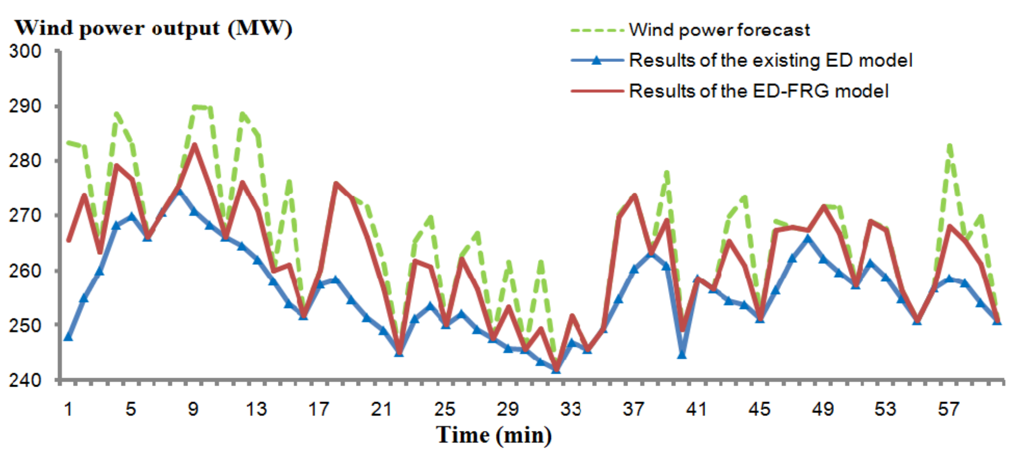

Figure 8. Wind power output curves in test scenario 1 of the 3-bus system

higher than those to solve the existing ED model, while the difference is acceptable since CPU times for both cases are within the same order of magnitude.

For both models in test scenario 1, the total thermal generation output curves are shown in Figure 10, and the wind power forecasts and output curves are shown in Figure 11. It can be seen that by using the ED-FRG model, the thermal generation can better follow the fluctuations of wind power to improve system wind utilization.

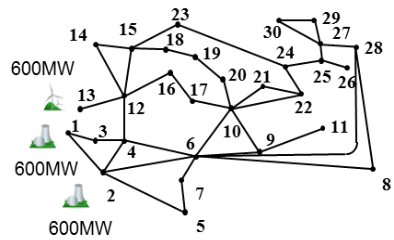

Figure 9. The IEEE 30-bus system to be studied.

Table 6. Curtailed Wind in the IEEE 30-bus Example (kWh)

Test scenario	1	2	3	4
Results of the existing ED model	18092.87	9499.56	15496.91	14411.25
Results of the ED-FRG model	7881.21	3368.23	5951.92	6356.42
Percentage of savings	56.44%	64.54%	61.59%	55.89%

Table 7. Generator Costs (¥) and CPU Times (s) in the IEEE 30-bus Example

Test scenario	1	2	3	4
Results of the existing ED model	165678.8	162370	166234.4	163048.2
CPU Time	1.62	4.53	5.45	5.32
Results of the ED-FRG model	164758.7	161854.1	165392.3	162328.7
CPU Time	5.97	7.07	6.92	6.66

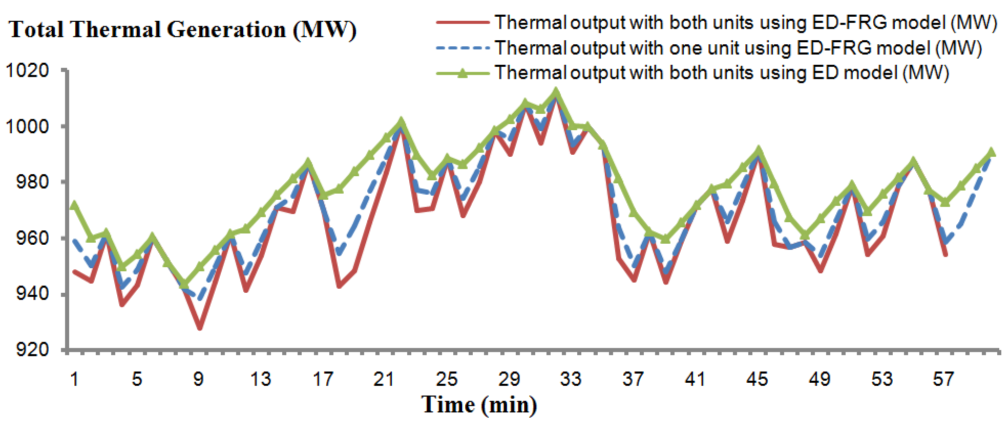

Figure 10. Total thermal generation output curves in test scenario 1 of the IEEE 30-bus system.

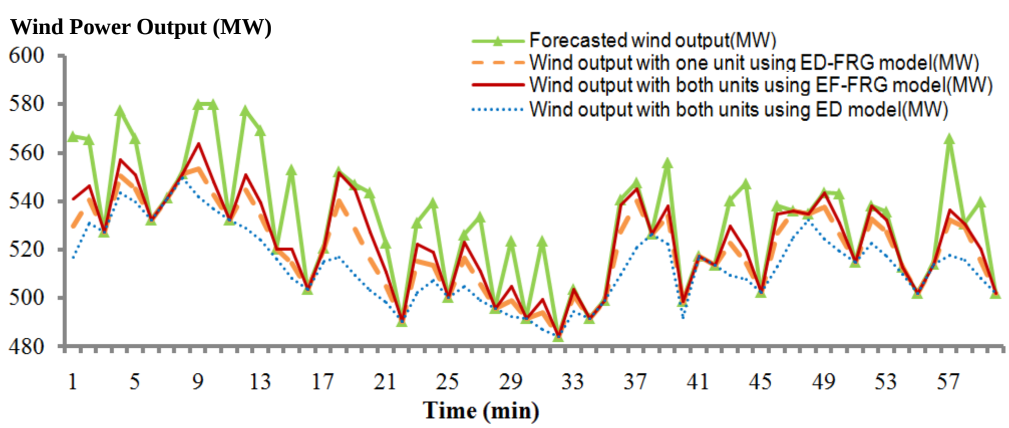

Figure 11. Wind power forecasts and output curves in test scenario 1 of the IEEE 30-bus system

5. Conclusions

In this paper, a new dynamic economic dispatch formulation is presented for wind-thermal power systems considering ramp rates and costs of fast mode generators. Our model differentiates from existing ones in that the objective is a two-variable, quadratic and positive definite cost function depending on both output levels and ramp rates of thermal units, and unit ramp rate limits vary with output levels. Numerical examples show that compared with existing models, our model can lead to better system dispatch results: in both examples the curtailed wind energy is saved by more than 50%, and generator costs are also reduced. The above results demonstrate that by taking into account more detailed information of thermal unit costs and ramp rates in economic dispatch, the system is able to operate more economically, and renewable energy can be better utilized.

Future research will consider more complicated ramp rate and cost characteristics of thermal units with, e.g., ramp rate limits being non-linear functions of output levels. Efforts are also needed to study the unit commitment problem with fast mode generators.

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