A Unified Approach to Load Dispatch and Pollution Control Optimization

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Abstract: With utility deregulation and more stringent pollution regulations in place, minimization of overall generation cost for a power company has become increasingly important. The major regulatory limitations can be normally translated into adjusting pollutant (such as NO_x and SO_2) control setpoints during a unit's daily operation. Additional reduction in pollutant levels beyond regulatory limits can bring in financial credit. However, pollution control is by no means easy or cheap, and the equipment operation and maintenance cost often becomes a burden to a generation company. For a company with multiple generating units, it is often difficult to determine the optimal load dispatch profile with optimal pollutant control levels taken into consideration such that the overall generation cost is minimal. This is simply because most of the existing economic dispatch practices are only based on net unit heat rate curves (or alternatively, incremental heat rate curves) which do not incorporate pollution control and other related costs. To overcome this problem with a more general approach, we present a unified framework for computing the optimal load profile together with the optimal pollution control

setpoints for a networked power plant system. In this new perspective, not only is the pollution control taken into account, but the unit ramp rate is also taken into consideration. The moving-horizon optimization can be performed over a time frame of interest. The advantage of the proposed approach over other existing methods will be discussed. Based on actual plant data, numerical case studies are presented to show the effectiveness of this new strategy.

Introduction:

Whenever there is a situation where two or more pieces of equipment make a common commodity, optimization is always possible. In a power plant, there can be multiple steam and power producers with varying efficiency, making it possible to economically assign loads among them based on their efficiency. An optimization program that runs on the plant's distributed control system (DCS) can perform this, because it has access to all of the data monitored by the DCS necessary for the calculation. Similarly, at the grid level, utilities have a need to satisfy the grid demand in the most cost-effective manner. Unlike the in-plant optimization that is performed on the power producing equipment in the plant, fleet-wide dispatching has multiple plants that can generate power with varying efficiencies. The in-plant optimization program has access via the DCS to efficiency data from each piece of equipment. In fleet-wide economic dispatch, all of the plants must be connected to a common network so a program in a central computer has access to all plant data. Until the development and deployment of advanced information technology over the last decade, a fully automated real-time economic load dispatch capability was not feasible.

Grid demands change rapidly, and the production facility that has reserve energy to dispatch will receive first consideration. Cost per megawatt is equally as important since the grid dispatcher has several facilities from which to choose. Therefore, operation management has a need to know how to be able to dispatch the power demands among the available facilities so that the power demand is satisfied at minimum cost. Traditionally, minimum cost could be thought of as economic dispatch among units based on heat rate, however, the amount of emissions produced and the cost of eliminating emissions must also be considered. For the past decade, U.S. utilities and industry have maintained an active exchange for emission credits for sulfur dioxide (SO_2), one of the key pollutants implicated in acid rain. Approximately two billion U.S. dollar worth of SO_2 credits are traded each year. Since utilities have been successful in reducing the amount of nitrogen oxides (NO_x) and SO_2 that is produced, it is estimated that a decade from now, one of the world's most vibrant and unusual markets will be dealing in our most notorious overabundant commodity, namely, the greenhouse gases (GHGs) believed to cause global warming [1]. The stock in trade will be tonnage permits allowing companies to emit specific quantities of carbon dioxide, methane, and other kinds of GHGs. No such world market has been officially sanctioned as yet, but some countries already have launched national markets, with private companies established as brokers, and trading has taken place on a trial basis.

The main point of emission trading is to reduce the overall cost of emission targets by giving industries strong incentives to meet goals and the flexibility to find the most cost-effective solutions. Organizations that manage to emit less than their allotted quota of gases by retrofitting plants, building cleaner or more efficient plants, or just shutting some down-- can profit by selling unneeded emission permits to companies unable to stay within their quotas.

Work has been done at the plant level that determines the loading of the combustion turbogenerators (CTG) and steam turbogenerators (STG) so that the power demand is satisfied at least cost taking into account the cost of ammonia injection for $NO_{x.}$ However, emission targets are on an area wide basis just like grid demand. Therefore, economically scheduling and operating power generation from the corporate level has become increasingly important. For example, Xcel Energy has already installed a fleet-wide optimization program using real-time data to optimize SO_2 emissions at three Denver-area power generation facilities [8]. The company is optimizing the SO_2 emission rate so that the total amount of SO_2 produced by these units does not exceed the yearly cap (10,500 tons of SO_2 per year), and ensure that the flue gas is scrubbed in the most cost-effective manner. It should be noted that this system is strictly for emissions, and plants' load demands are still assigned by the dispatcher and become constraints in the SO_2 optimization formulation.

The dispatcher for a power company that has multiple plants with various forms of power generation and emissions equipment really needs one program that will dispatch the load for the lowest overall operating cost. This means that, in addition to heat rate, dispatchers must also consider scrubber efficiency, fuel cost, scrubber reagent (e.g., ammonia, limestone) costs, and emission credits. Not only do power demands have to be satisfied but environmental pollution constraints must also be met. To solve these two-coupled objectives, this paper presents a unified framework and optimization strategy along with case study result that demonstrate the optimal determination of load dispatch and pollution control setpoints in a multi-unit environment.

Unified Load Dispatch and Pollution Control Optimization

Before real-time fleet-wide economic dispatch can be performed, the optimization program must have access to each of the plant's heat rate, emission costs, equipment availability etc. in real-time. In order to do this the plants must be able to exchange information with each other. The optimization program resides in a central location and each plant's control system is connected to the corporate network. The optimization program sends load and scrubber efficiency setpoints to the plants. The typical network configuration is shown in Figure 1.

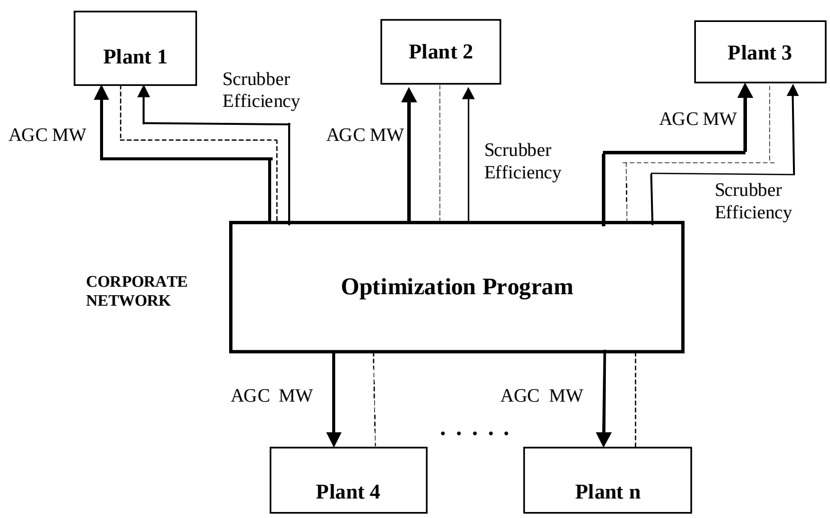

FIGURE - 1
NETWORK CONFIGURATION

The plants connected to the network may include coal-fired steam-electric generating units containing low NO_x burners that keep the NO_x emission rate at a minimum. The SO_2 emissions may be controlled by the use of flue gas de-sulfurization (FGD) systems. Other coal-fired units may have combustion optimization systems that minimize NO_x production. There may be combined cycle plants that utilize natural gas thus eliminating SO_2. However, the cost of gas is higher than the cost of coal and these combined cycle plants still produce NO_x ([2], [3]). Regardless of the type of plants, the information from the plants must be readily available on the computer where the optimization program is running.

Modern networking technology has made the automatic generation control

(AGC) a common practice in today's power industry. This would mean that the economic dispatch can be easily implemented from a dispatch center through remote control. However, recent utility industry deregulation and restructuring make the decision making process more complicated. Energy transmission and distribution can now be carried out across control areas. Independent power producers (IPP) have more freedom to serve the grid demand, and power generation is more tightly engaged with energy trading. For example, electrical transmission flow constraints can sometimes force a costly unit to be on-line and prevent the optimal dispatch from being fully realized. One drawback for the existing economic dispatch practice is that all emission limitations are passively treated as constraints in the decision making process. Typically, pollutant removal scrubber setpoints are fixed at constant values. The adjustment of scrubber setpoints is usually separately considered from load dispatch. Work has been done to consider load dispatch and pollutant removal efficiency setpoints together [4]. However, unit ramp rate constraint was not considered during the optimization.

Strictly speaking, many of the processes involved in the optimization decision making are dynamically changing. The change can be slow or fast. When an optimal load profile is calculated and sent out from the dispatch center, it often takes hours for the lower level plants to reach their desired load levels due to inherent process dynamics. Therefore, the unit ramp rate is explicitly incorporated in the proposed optimization scheme in this paper.

First of all, a fundamental assumption is made that all units' scrubber setpoints can be adjusted from a remote-dispatching center. Fortunately, the state-of-the-art networking technology makes it a feasible and easy implementation. For this study, the simulation models were targeted at major factors that affect the overall generation cost, namely, the heat rate model, fuel cost, emission constraints and control costs, and the emission reduction credit. To focus on presenting the key concept without introducing unrelated complexity, electrical transmission loss and transmission flow constraints are not considered in this work. These factors can be easily incorporated into the scope of the current work whenever needed. Therefore, the proposed strategy is most appropriate for the situation where all units under consideration are within the same control area. However, in the case where units from different control areas are involved in dispatching, the transmission flow constraint can be included in the current formulation in a straightforward manner.

It is worth noting that, to separate our current work from a long-term load forecasting and scheduling problem, fuel transportation and storage scheduling related cost are excluded from the optimization formulation. We assume there are a total number of n units in the network. These units are not necessarily located in one plant. The objective is to minimize the total generation cost for a foreseeable time period (horizon) where the desired total load profile is available. This includes the situation where the total load demand ramps from one setpoint up or down to another level. We assume this short range forecasted total load demand profile is always available.

For general discussion, let the goal be ramping the total load from current L_0 (at time T_0) to L_e (at time T_e), and possibly stay at L_e for an extended period of time. It is assumed the overall optimization time horizon $\{T_0, T\}$ (with $T \geq T_e$) is divided by *N* time segments $\{t_0, t_1\}$, $\{t_1, t_2\}$ .... $\{t_{N-1}, t_N\}$ with $t_0 = T_0$ and $t_N = T$. The total load at the end of each time segment is denoted by $L_1, L_2, ..., L_N$. The intermediate target load L_k ($k = 1,....,N$) can be simply computed as the linear interpolation between the initial total load and the final total load:

$$L_k = L_0 + k \cdot (L_e\text{-}L_0)/(T_e - T_0) \quad \text{(for } t_k \leq T_e\text{)} \quad (1)$$
$$L_k = L_e \quad \text{(for } t_k > T_e\text{)}$$

We define the following cost items that will be taken into account in the decision making process. The cost associated with the fuel consumption for the i^{th} unit at time t_k can be expressed as:

$$F_i^k = L_i^k \cdot H_i^k \cdot f_i \quad (2)$$

Where L_i^k = load for the i^{th} unit at time t_k

H_i^k = heat rate for the i^{th} unit at time t_k

f_i = fuel price for the i^{th} unit.

Recall *n* is the total number of generation units in consideration, and therefore $1 \leq i \leq n$.

For units with a scrubber installed, there is the scrubber reagent cost. For example, the SO_2 flue gas desulphurization (FGD) system uses the limestone. For boilers that have a selective catalytic reduction (SCR) system, there is a cost associated with the ammonia usage. Depending on the reagent used, there is a certain amount of waste that is produced. This waste disposal cost must be considered when calculating a final reagent cost. Regardless, the overall cost can be calculated in terms of $/lb of reagent. Therefore, for the i^{th} unit with scrubber the cost for reagent consumed at time t_k can be expressed as:

$$R_i^k = \sum_{j=1}^{m} \left\{ S_{i,j}^k \cdot p_{i,j} \right\} \quad (3)$$

Where $S_{i,j}^k$ = j^{th} reagent flow for the i^{th} unit at time t_k

$p_{i,j}$ = j^{th} reagent price for the i^{th} unit

m = total number of pollutant types being controlled.

The typical reagents are NH_3 (for SCR) and limestone (for SO_2 control).

The credits for SO_2 and NO_x should be subtracted from the operating cost. The credit in either case is applied to the difference between the actual amount of pollutant produced and the allowable amount. It should be noted that the allowable overall amount of pollutant as well as the limitations for each plant are hard constraints ensuring that any solution will not violate the regulation. Thus, the emission credit for the j^{th} pollutant at time t_k can be expressed as:

$$C_j^k = \left(X_j^k - \sum_{i=1}^{n} Z_{i,j}^k \right) \cdot c_j \qquad (4)$$

Where X_j^k = total regulation limit for the j^{th} pollutant at time t_k

$Z_{i,j}^k$ = j^{th} pollutant produced by the i^{th} unit at time t_k

c_j = bonus price for the j^{th} pollutant

Let the total cost (\$/hr.) at t_k be represented by J_k. Then, it follows that

$$J_k = \sum_{i=1}^{n} F_i^k + \sum_{i=1}^{n} R_i^k - \sum_{j=1}^{m} C_j^k \qquad (5)$$

Therefore, the total cost J for the time interval $\{T_0, T\}$ can be shown as ([5]):

$$J = \sum_{k=1}^{N} J_k \qquad (6)$$

We denote the load demand for unit i at time t_k by $L_{i,k}$, and its maximum ramp rate during any time interval $\{t_{k-1}, t_k\}$ by M_i. Let the minimum and maximum load for the i^{th} unit be $L_{i,\min}$ and $L_{i,\max}$, and the j^{th} pollutant limit for the i^{th} unit be $X_{i,j}$. Then, minimization of the total generation cost over time horizon $\{T_0, T\}$ with load demands and scrubber setpoints as decision variables can be formulated as

Minimize *J*

Subject to the following constraints:

Load constraints:

$$\sum_{i=1}^{n} L_{i,k} = L_k \qquad (7)$$

$$L_{i,\min} \le L_{i,k} \le L_{i,\max} \qquad (8)$$

Unit ramp constraint:

$$-M_i \le L_{i,k+1} - L_{i,k} \le M_i \qquad (9)$$

Emission constraint:

$$\sum_{i=1}^{n} Z_{i,j}^{k} \leq X_{j}^{k} \qquad (10)$$

$$Z_{i,j}^{k} \leq X_{i,j} \qquad (11)$$

(k = 1, …, N, i =1,…, n, j =1,…., m)

Some of the details in the above optimization formulation need to be discussed here. First, the division of the load profile into N time segment determines how many decision variables are involved in the optimization computation. The finer the division is, the more precise the scheduled load profile will be. However, the computation burden will increase dramatically as the time horizon is divided into more segments. Second, the load profile between the beginning and end of the ramp does not have to be linear interpolation as shown in Eqn.(1). The intermediate loads L_k can be chosen as decision variables whose values will be determined by the optimization. The optimization criterion can be either minimum cost or minimum ramp time. Third, the optimization objective function defined in Eqn.(6) provides the opportunity for a moving horizon formulation. The optimization can be performed over a preview horizon as long as the forecasted total load demand is available. This is especially useful for a power network with fast moving total demand and relatively slow-ramping units.

Most plants' heat rate characteristics are nonlinear in that they have a high value at the low load and flatten out at the high end. The mid load level change is usually quite dramatic. This is especially true for a combined cycle unit when different combinations of CTG and HRSG (Heat Recovery Steam Generator) are involved. In this paper, polynomial regression models were used whenever possible. However, when traditional regression strategy did not fit well, feedforward neural network models were used instead. Also worth of mentioning is that, by formulating the optimization in the form of equation (6), the pollution control credit is realized immediately as capital income or profit. This is a simplification, since the emission trading process takes time to realize. The treatment of emission trading market, which may turn out to be another optimization strategy, is outside the scope of this study.

To compare with the traditional incremental heat rate curve based method, the formulation proposed in this paper uses nonlinear programming directly. A state-of-the-art nonlinear optimization routine can robustly handle non-smooth and non-convex functions. Given the involvement of pollutant removal setpoints and some of the non-convex heat rate characteristic (e.g., heat rate for combined cycle units), it is impossible to directly apply the incremental heat rate method for dispatching optimization. On the other hand, as is typical for any nonlinear optimization strategy, problems may be encountered in the effort of pursuing the true global optimum solution. In an on-line implementation, an evolutionary technique may be used to maximize the chance of finding the global optimum solution.

As a last note, the fleet-wide multi-unit dispatching is only as accurate as the unit data supplied to it. Many models considered have more or less slow time-varying characteristics. For example, the heat rate models are normally obtained from the lower level plants. Due to equipment aging and process drift, these models need to be updated constantly. Fuel price and regulatory policy change also introduce variations to the models. To find the true optimum load assignments the plant data supplied to the dispatch center should be current. In addition, the data from the plants should be based on running in an optimum manner. If the plants are running in a non-optimum mode, then the data used by the dispatch center might assign loads in such a manner that a less efficient plant is utilized in favor of a more efficient plant.

Sample Power Network and Case Study

For this case study, we consider a power network consisting of six generating units. Utility boiler 1(UB1) is a coal-fired steam-electric 200 MW generating unit. This plant contains low NO_x burners that keep the NO_x emission rate at 0.2 lb NO_x/mBtu. The SO_2 emissions are controlled by the use of a lime spray dryer (LSD) FGD system. The reagent used in this system is lime slurry that is sprayed into a reactor vessel in a cloud of fine droplets. This LSD system has a maximum removal efficiency of 90%. Utility boiler 2 (UB2) is a 120 MW coal fired plant similar to UB1 except it contains a duct sorbent injection (DSI) FGD system. According to [7], a DSI system dry reagent is injected directly into the flue gas duct between the air preheater and the particulate control device. Commercially available limestone ($CaCO_3$) or hydrated lime ($Ca(OH)_2$) is used as sorbent. This unit has a maximum removal efficiency of 50%. Utility boiler 3 and 4 (UB3&4) are another two coal fired steam-electric generating units. Unlike UB1 and UB2, these 700 MW and 800 MW plants do not have a FGD system. Instead of having low NO_x burners, each of them contains an SCR system to reduce NO_x emissions. In this system, ammonia (NH_3) is injected into the flue gas within a temperature range of 315-400 ^oC, which then passes through layers of catalyst in a reactor. The NH_3 and NO_x (NO) react on the surface of the catalyst, forming molecular nitrogen (N_2) and water. This power network also contains two 250 MW combined cycle plants, namely CC1 and CC2. Each plant contains two CTG each with its own HRSG. The HRSG's produce high and low pressure steam. All of the high pressure and part of the low pressure steam feed the common STG. A portion of the remaining low-pressure steam is sent to the deaerator and the remainder is injected into the CTGs to reduce NO_x.

For each plant there is a Heat Rate vs. Load relationship. For plants UB1, UB2, UB3, and UB4 there are equations that define the amount of SO_2 and NO_x produced for a given load. On UB1 and UB2, the amount of limestone required to limit the SO_2 production is defined, and on UB3&4 the amount of ammonia required to limit the NO_x is defined. The models for predicting the operation and maintenance costs associated with the ammonia process were derived from [6]. The combined cycle plants burn gas and, therefore, do not produce any SO_2. However, even they have steam injection; a small amount of NO_x is still produced. The total amounts of SO_2 and NO_x are constrained not to exceed the allowable amounts hence preventing any emission penalties. However, the minimum constraints on the emission variables can be zero allowing emission credits to be considered. In addition, there are constraints that define the operating ranges of the equipment. For example, there are the minimum and maximum loads for the plants. Likewise there are minimum and maximum removal efficiencies for the FGD and SCR systems. Finally, in all simulation case studies, equation (1) is used to calculate the total load profile.

Table I identifies the cost and credit for each unit.

TABLE I

DESCRIPTION	VALUE	UNITS
Utility Boiler 1 Fuel Cost	1.3	\$/mBTU
Utility Boiler 1 Lime Slurry Cost	0.045	\$/Lb
Utility Boiler 2 Fuel Cost	1.3	\$/mBTU
Utility Boiler 2 Lime Cost	0.04	\$/Lb
Utility Boiler 3 Fuel Cost	1.3	\$/mBTU
Utility Boiler 3 NH3 Cost	0.11	\$/Lb
Utility Boiler 4 Fuel Cost	1.3	\$/mBTU
Utility Boiler 4 NH3 Cost	0.11	\$/Lb
Comb Cycle 1 Fuel Cost	2.1	\$/mBTU
Comb Cycle 2 Fuel Cost	2.1	\$/mBTU
SO_2 Credit	0.05	\$/Lb SO_2
NO_2 Credit	2	\$/Lb NO_2

The heat rate curve for each unit is shown in figures 2 and 3.

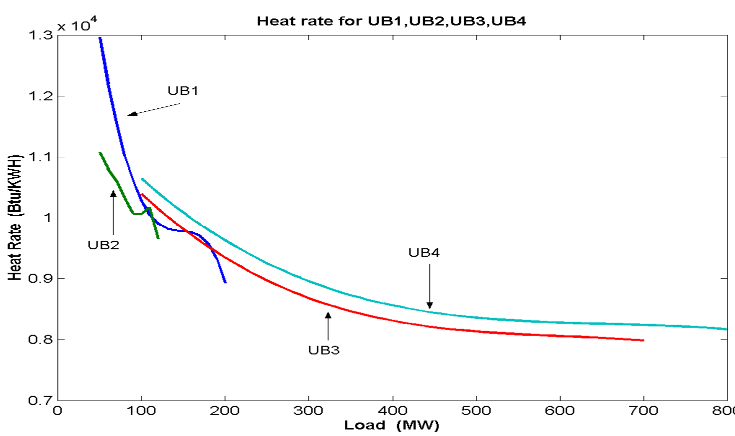

Figure 2. Heat rate for UB1,UB2,UB3 and UB4

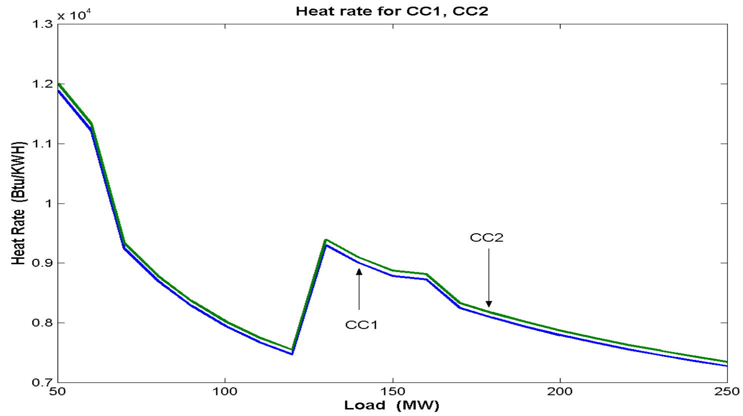

Figure 3. Heat rate for CC1 and CC2

Case I. We assume UB4 is out of service and the rest of the units are available. The total load demand is to ramp from 1100MW to 1520MW in about 84 minutes. The maximum ramp rate for all units is assumed to be 7MW per minute. The results for each unit load and scrubber efficiency setpoint during the simulation time are shown in figures 4 and 5. As we can see, at 1100MW level UB1,UB2,CC1, and CC2 are all brought to full load already. UB3 is the only unit that has the room to ramp up and make up the total demand. At the beginning of the ramp, all scrubber setpoints are kept at their minimums to bring the cost down. As UB3 ramps to certain point (total load around 1170MW), the SCR removal setpoint starts to go up due to the limit imposed on total NO_x. As the unit keeps going up to certain point (total around 1480MW), the FGD efficiency setpoints for UB1 and UB2 will have to be raised in order to meet the pollution regulation constraint. Fixing pollutant removal efficiency setpoints would make it difficult to achieve cost reduction and regulatory compliance at the same time.

Case II. Assuming only UB3 and UB4 are available in this network. The input NO_x before the SCR is 0.5 lb/mBtu for UB3 and 0.45 lb/mBtu for UB4. The goal is to ramp the total load from 1200MW to 1500MW in 40 minutes. The load ramp result is shown in Figure 6. Two points can be made from this example. First, UB4 ramps up first and faster than UB3 even if it has the worse heat rate. This is due to the fact that UB4 has lower NO_x emission rate and this directly translates into credit and savings. Second, the NO_x removal setpoint for both units are computed at the minimum (80%). This would otherwise be unknown to operation had the optimization study not been implemented either off-line or on-line. In a different scenario, if UB3's NO_x removal efficiency setpoint is fixed at 95% for the purposes of maximum NO_x reduction, then the optimally computed load dispatch profile is completely different. This time UB3 ramps up first, as illustrated in Figure 7. This is because further NO_x reduction increases NH_3 usage cost, and this cost cannot be effectively offset by the increased NO_x credit. This case study exactly demonstrates the key point of this paper that, from minimum cost standpoint, the decision on setting the unit pollutant removal rate interplays with the determination on load dispatch; therefore, all factors need to be considered together in a unified manner.

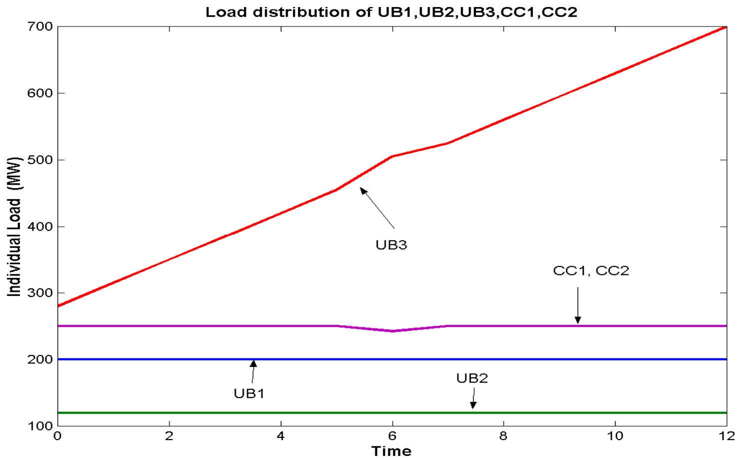

Figure 4. Five-unit load ramp profile (time scale: x 7 minute)

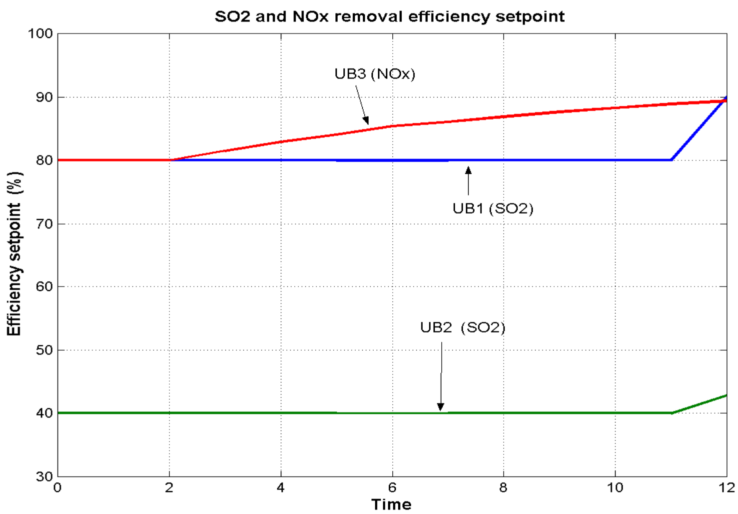

Figure 5. Scrubber efficiency setpoint change (time scale: x 7 minute)

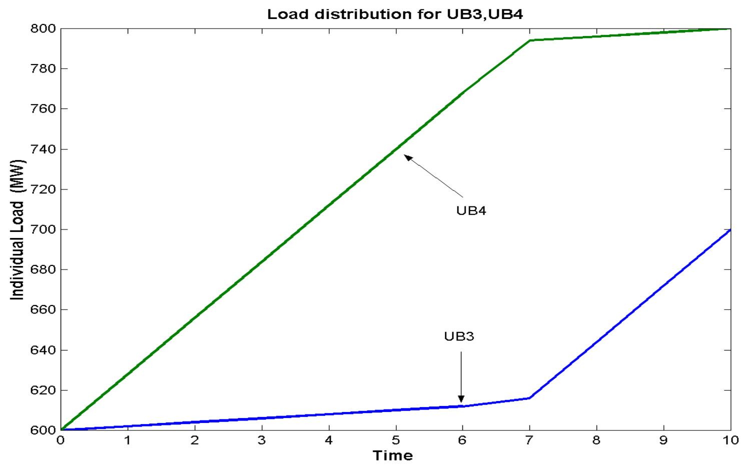

Figure 6. Two-unit load ramp profile (time scale: x 4 minute)

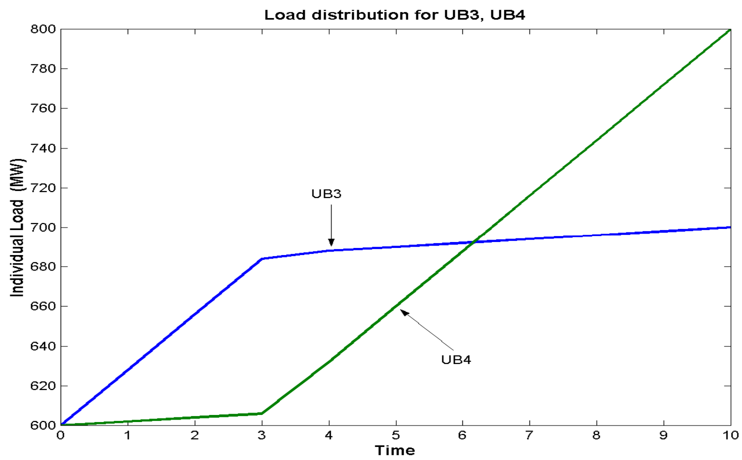

Figure 7. Two-unit load ramp profile --- Fixed UB3 NO_x removal efficiency at 95%
(time scale: x 4 minute)

Conclusion

This paper presents a methodology that optimizes the total generation cost in a unified framework. Both the load dispatch and the scrubber reagent usage are considered together in one optimization run. A direct nonlinear programming approach is utilized to obtain the optimal solution. It is expected this unified method will provide benefit for generation companies in reducing production cost in real-time operation as well as in off-line simulation study. Due to the tightened emission regulations and the recent utility industry restructuring, the cost of generation is not just limited to fuel consumption and heat rate. More factors that impact the total cost have to considered in the decision making process systematically. Our future work will identify other factors that may potentially affect the generation cost, and hopefully take these factors into account in designing strategy for efficiency improvement and cost reduction.

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