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Optimal scheduling of combined heat and power plants using mixed-integer nonlinear programming

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ABSTRACT

This paper presents the application of MINLP (mixed-integer nonlinear programming) approach for scheduling of a CHP (combined heat and power) plant in the day-ahead wholesale energy markets. This work employs first principles models to describe the nonlinear dynamics of a CHP plant and its individual components. The MINLP framework includes practical constraints such as minimum/maximum power output and steam flow restrictions, minimum up/down times, start-up and shut-down procedures, and fuel limits. Special care is given to the explicit modeling of the unit start-up types (hot, warm, and cold), which depend on the component's prior reservation time, resulting in the differences in the time-dependent start-up costs of generating units. The model also accounts for the different operating modes (synchronization, soak, dispatch, and desynchronization) during start-up and shut-down of each unit. We provide case studies involving the Hal C. Weaver power plant complex at the University of Texas at Austin to demonstrate the effectiveness of the proposed methodology. The results show that the optimized operating strategies can yield substantial net incomes from electricity sales.

1. Introduction

Efficient energy use in power generation industry has a significant impact on operating costs due to volatile cost of energy today. As the use of fossil fuels for power generation and cogeneration is expected to grow during the next 20 years [1], it is necessary to analyze how to best operate existing plants that utilize fossil fuels as their primary energy sources. The efficient and clean energy solution is a combined heat and power technology.

CHP (Combined heat and power) is a technology that decreases total fuel consumption and related greenhouse gas emissions by producing both electricity and useful thermal energy from a single energy source [2]. If a CHP system is strategically located at or near the point of energy use (commercial or residential buildings), the effluent heat from a gas turbine can be readily recovered and used to heat the neighboring buildings [3,4]. As a result, typical CHP systems exhibit high efficiencies up to 75%, whereas conventional energy supply systems yield around 51% efficiency [5,6]. Distributed electricity generation systems, such as CHP, can also substantially reduce transmission costs and efficiency losses as the power does not have to be transported using high-voltage power lines over long distances as compared to larger, centralized power plants [7]. The vast majority of existing and planned CHP installations use natural gas as the primary fuel.

In the industrial and commercial sectors, a typical CHP site relies upon the electricity distribution network for significant periods, i.e., for purchasing power from the grid during periods of high demand or when off-peak electricity tariffs are available [8]. On the other hand, in some cases, a CHP plant is allowed to sell surplus power to the grid during on-peak hours when electricity prices are highest while all operating constraints and local demands are satisfied. This is achieved by the ED (economic dispatch), which assigns the system load demand to the committed generating units for minimizing the power generation cost [9]. The net income of a CHP plant obtained by participating in wholesale energy markets can be significant, especially during the late afternoon or early evening hours when peak demand occurs. Due to such a compelling potential profit opportunity, the ED of a CHP plant is attracting a great deal of attention and is one of the two important tasks considered in power system generation scheduling problem. The other is the UC (unit commitment) that determines the unit start-up and shut-down schedules in order to minimize the system fuel expenditure when more than one generating unit exists. In other words, an important criterion in power system operation is to meet the power demand at minimum fuel cost using an optimal mix of different generating units [10].

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Application of ED to district heating and cooling networks that incorporate CHP (i.e., university, airport, and hospital) have been popular as the system loads (heat and electrical) fluctuate considerably with time of day/year. CHP applications in district heating and cooling networks can be found in several references [11–14]. For example, the optimal size of a CHP system under British spot market conditions [11] and under German spot market conditions [14] is analyzed. Ristic et al. [12] used three different cost functions, each of which was formulated as a LP (linear programming) problem for each time step. By comparing the solutions from the three functions, the lowest cost during a time step defines the optimal operation of the CHP system. However, this model is empirical in that heat production was assumed to be proportional to electricity production. Rolfsman [13] showed that the optimal operating strategy allowed the CHP units that include TES (thermal energy storage) to operate at full-load condition when electricity prices are high, storing the excess heat produced in the TES units. The TES would then be discharged during off-peak hours when it was not economic to produce electricity. Ito et al. [15] combined the dynamic programming method with mixed-integer programming to determine the optimal operation of a diesel engine cogeneration plant. Their study only covers 12 representative days for the whole year with a fixed-rate electricity price for summer and that for winter. So, the model does not reflect the diurnal variation in electricity prices. The work shown in Ref. [16] has similarities to [15], but it included a space-cooling demand. The optimization problem was formulated as a large-scale MILP (mixed-integer linear programming) problem and was solved by means of the decomposition method. Lawrence Berkeley National Laboratory developed one of the most advanced CHP optimization strategies [17]. This sophisticated model optimizes a distributed microgrid of several CHP systems, electricity generators, heat boilers, and heat storage tanks. The objective function takes into account fuel costs, operation and maintenance costs, carbon emission taxation, and investment costs. However, the model does not consider the possibility of interconnection to the external grid. Stoppato et al. [18] proposed a model that accounts for additional costs associated with the cyclic type of operation (i.e., unit start-ups and shutdowns) and with unplanned maintenance and unavailability of the plant if a failure occurs, due to creep and thermo-mechanical fatigue loadings. Nevertheless, this model is limited to a steam power plant.

Happ [19] presented a comprehensive survey on ED, which covers several aspects: developments in ED since early 1920's, valve point loading, multi-area concepts in economic dispatch, and optimal load flow. Chowdhury and Rahman [20] presented a survey addressing various aspects of ED during the period 1977–88, namely: optimal power flow, ED in relation to AGC (automatic generation control), dynamic dispatch, and ED with non-conventional generation sources. The fuel cost of the generator described in Refs. [19,20] is approximately represented by polynomial functions (mostly a single quadratic function as this is convex in nature) for ED computation. It is also standard industrial practice that polynomial functions are predominantly used to estimate the fuel cost of generator as the resulting ED problem can be solved as convex optimization problem. In actual practice, however, this assumption (quadratic or piecewise quadratic, monotonically increasing cost functions) is not valid because the cost functions exhibit higher order nonlinearities and discontinuities due to prohibited operating zones, multiple fuels, and valve point loading effects [21,22]. DP (dynamic programming) [23] has been used to overcome these difficulties, but due to the curse of dimensionality and excessive evaluation at each stage it has limitations. GA (genetic algorithm) is a potential solution methodology for nonconvex ED problem due to the independence of the objective function from the auxiliary information such as differentiability and continuity [21,22,24–29]. However, the disadvantages of the GA are its slow convergence speed near the global optimum and long computational time. PSO (particle swarm optimization) [30,31] is another way to deal with a nonconvex ED problem but is prone to the same problems associated with GA (slow convergence and stagnation phenomenon in the proximity of the optimal solution). Dotzauer et al. [32] solved the operational optimization problem of a CHP plant that includes TES by using a LR (Lagrangean relaxation) approach. Rong et al. [33] extended the work shown in Ref. [32] and included restrictions on minimum up/down times. In a number of studies [34–36], a dynamic process was performed in conjunction with ED in order to satisfy the ramping constraints.

Operating constraints such as minimum up/down times and ramping limits that are modeled in some of the previously mentioned references result in a complex optimization problem and originate from the so-called unit commitment problem. Besides the methods mentioned previously, i.e., DP, GA, PSO, and LR, other approaches have been proposed to address the UC problem such as exhaustive enumeration [37], priority listing [38,39], branch and bound [40,41], interior point optimization [42], tabu search [43,44], simulated annealing [45], fuzzy logic [46], artificial neural networks [47,48], evolutional programming [49,50], and hybrid models [51–53] as well as mathematical programming, i.e., MILP and MINLP (mixed-integer nonlinear programming). For a detailed review on various methods of generation scheduling in electric power systems, see Refs. [54,55]. Nowadays, among all methods, MIP (mixed-integer programming) is the method of choice due to advances in solution algorithms and computing power [56]. In practice, many US ISOs (independent system operators) use MIP for generation UC within the electric industry.

Arroyo and Conejo [57] proposed an MILP formulation for the UC and Carrion and Arroyo [58] improved the model shown in Ref. [57] by reducing the number of binary variables. Liu et al. [59] introduced an MINP model, which considers “units” of individual components within the plant, and showed that their model is superior to an aggregated mode model for the scheduling of CCCT (combined cycle combustion turbine) plants due to the more accurate description of the physical range of operation. Aghaei and Alizadeh [60] considered a scheduling problem of a CHP-based microgrid as an MIP-based multi-objective (i.e., minimizing total operational cost of the plant and minimizing carbon emissions) optimization problem. Mitra et al. [61] developed a deterministic MILP model that allows optimal production planning for continuous power-intensive processes. They emphasized the systematic modeling of operational transitions that result from switching the operating modes of the plant equipment, with logic constraints. Mitra et al. [62] extended their previous work and modeled transitional behavior (i.e., warm and cold start-ups and shut-downs) with different operating modes. However, all the works shown in Refs. [60–62] used empirical models to relate the power production rate to the fuel consumption, thus the operating cost of generator.

The solution of the scheduling problem strongly depends on the accuracy of the plant models used for simulations. Therefore, it is critical to develop the plant models that establish physically correct quantitative relationships between real systems and models of those real systems. For processes that operate over a wide range of operating conditions or often close to the boundaries of admissible regions due to tight economic and environmental conditions, linear or/and empirical models are unsuitable to adequately describe the process dynamics. Therefore, complex nonlinear models must be used.

In this work, we propose an MINLP framework for optimal scheduling of a CHP plant in the competitive wholesale energy

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