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Optimal day ahead scheduling of combined heat and power units with electrical and thermal storage considering security constraint of power system

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A B S T R A C T

The use of Combined Heat and Power (CHP) with an overall efficiency from 70 to 90% is one of the most effective solutions to optimize the energy consumption. Mainly due to interdependence of the power and heat in these systems, the optimal operation of CHP systems is a complex optimization problem that needs powerful solutions. This paper addresses optimal day-ahead scheduling of CHP units with Electric Storage Systems (ESSs) and Thermal Storage Systems (TSSs) considering security constraints. Basically, the optimal scheduling of CHP units problem is a Mixed Integer Non Linear (MINLP) problem with many stochastic and deterministic variables. In this paper, linearization techniques are adopted to linearize equations and a two-stage Stochastic Mixed-Integer Linear Programming (SMILP) model is utilized to solve the problem. The first stage models behavior of operation parameters and minimizes the operation costs meanwhile the second stage considers the system's stochastic contingency scenarios. The proposed method is applied to 18-bus, 24-bus IEEE test systems. The effectiveness of the proposed algorithm has been investigated.

1. Introduction

The increasing utilization of distributed cogeneration facilities, e.g., Combined Heat and Power (CHP) systems contributes to increase the efficiency of the energy system infrastructure and the interdependencies of heat and electricity systems [1].

The Optimal day ahead Scheduling of Combined Heat and Power (OSCHP) units problem consists of determining the optimal day ahead Unit Commitment (UC) of generation units depend on the system loads, reliability criteria, dynamic and characteristics of devices and cost-benefit analysis. The OSCHP must be logical in light of demands and heat-electric energy systems optimal operation. However, the main operation decisions are critical due to the two-way ESU and ICs interactions what will happen now to what will happen later based on system dynamic constraints. In addition, many dynamic interdependencies of heat and electric systems should be adequately modeled to capture the real nature of the problem. Thus, the OSCHP problem has a slave problem that optimizes the hourly electric and heat power flow based on hourly dynamic constraints and interdependencies. This problem is known as Optimal Power Flow (OPF) or Economic Dispatch (ED) problem based on its objective function formulation [2].

The problem of UC involves finding the least-cost dispatch of available generation resources to meet the electrical load. In addition, generating plants are subject to a number of complex technical constraints; the UC problem 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 The Federal Energy Regulatory Commission (FERC) in the US defined cogeneration as “the combined production of electric power and useful thermal energy by sequential use of energy from one source of fuel” [3].

These constraints are amenable to mathematical programming as linear or mixed-integer constraints. This program typically make use of mathematical optimization techniques such linear

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Nomenclature

Index sets
t Hour index
m,n Bus indices
i Index of generating units
l Index of transmission line.
NS Scenario index
msf Segment index of piecewise linear cost function

Parameters
$Cap_{storage}$ Capacity of ESS (kW)
$HCap_{storage}$ Capacity of TSS (kW)
$CD_{storage}$ Cost of ESS discharge ($/kWh)
$CC_{storage}$ Cost of ESS charge ($/kWh)
$CHD_{storage}$ Cost of TSS discharge ($/kWh)
$CHC_{storage}$ Cost of TSS charge ($/kWh)
$\eta_{CHP}(i)$ Electric efficiency of the CHP system connected to bus i at hour$t$
gp Gas price ($/kWh)
$OM_{CHP}(i)$ Operation and maintenance variable cost of CHP system connected to bus i ($/kWh)
$HR_{CHP}(i)$ Heat rate of CHP system connected to bus i(kJ/kWh)
$P^{min}_{CHP}(i)$ Minimum active power of the CHP system connected to bus i at hour t (kW)
$P^{max}_{CHP}(i)$ Maximum active power of the CHP system connected to bus i at hour t (kW)
$P^{min}_{Conv}(i)$ Minimum active power of the conventional system connected to bus i at hour t(kW)
$P^{max}_{Conv}(i)$ Maximum active power of the conventional system connected to bus i at hour t(kW)
$F^{min}()$ Minimum production cost of conventional unit ($)
$\alpha^{th}_{CHP}(i), \beta^{th}_{CHP}(i), \gamma^{th}_{CHP}(i)$ Coefficient of heat-power feasible region for the CHP units
$H^{min}_{Boiler}(i)$ Minimum output of the boiler connected to bus i at hour t(kW)
$H^{max}_{Boiler}(i)$ Maximum output of the boiler connected to bus i at hour t(kW)
$\eta_{Boiler}(i)$ Efficiency of the boiler connected to bus i at hour$t$
$ILT_{max}(i,t)$ Maximum involuntary load curtailment of bus i at hour t(kW)
$ILT^{bus}_{max}(i)$ Maximum involuntary load curtailment of bus i (kW)
$ILP(i)$ Value of lost load in bus i($/kWh)
$\zeta_{Gen}(i,NS), \zeta_{Line}(i,NS)$ Outage of generating units and transmission lines matrix
$PE_{Demand}(i,t)$ Total load demand of bus i at hour t(kW)
$HE_{Demand}(i,t)$ Thermal power required by bus i at hour t(kW)
$Prob(NS)$ Probability of scenario NS
$X_{mn}(l)$ Reactance of line l (Ω)
$Pflow^{max}$ Maximum capacity of line l(kW)
$ep(t)$ Electricity price at hour in the upstream network ($/kWh)
L_b Number of transmission lines connected to bus b
T Number of scheduling hours
N Number of buses
T_{NS} Number of Scenarios

Variables
Obj Objective function
$Benefit$ Benefit of network
$Revenue$ Revenue of network
$cost$ Overall cost during the schedule period ($)
$Cost_{CHP}(i,t)$ Cost of generating with CHP system connected to bus i at hour t($)
$Cost_{Conv}(i,t)$ Cost of generating with CHP system connected to bus i at hour t($)
$Cost_{Boiler}(i,t)$ Cost of generating heat via the boiler connected to bus i at hour t($)
$Cost_{Buy}(t)$ Cost of purchased electricity from the upstream network at hour t($)
$Cost_{storage}(t)$ Cost of generating electricity and heat via the ESS and TSS connected at hour t($)
$Cost_{LC}(t)$ Cost of generating electricity and heat via the ESS and TSS connected at hour t($)
$Cost_{SC}(t)$ Cost of the security at hour t ($)
$SC(NS,t)$ Cost of the security at hour t in scenario NS($)
$P_{storage}(t)$ Active power generation via ESS at hour t(kW)
$PD_{storage}(t)$ Power discharge of ESS at hour t(kW)
$PC_{storage}(t)$ Power charge of ESS at hour t(kW)
$X(t)$ Binary variable associated with discharge of ESS; 1 if the ESS is discharged at hour t and 0 otherwise.
$Y(t)$ Binary variable associated with charge of ESS; 1 if the ESS is charged at hour t and 0 otherwise.
$Pg(t)$ Total active power generation at bus i at hour t(kW)
$P_{Conv}(i,t)$ Active power generation via conventional generation connected to bus i at hour t(kW)
$H_{storage}(t)$ Active power generation via TSS at hour t(kW)
$HD_{storage}(t)$ Power discharge of TSS at hour t(kW)
$HC_{storage}(t)$ Power charge of TSS at hour t(kW)
$XH(t)$ Binary variable associated with discharge of TSS; 1 if the TSS is discharged at hour t and 0 otherwise.
$YH(t)$ Binary variable associated with charge of TSS; 1 if the TSS is charged at hour t and 0 otherwise.
$P_{CHP}(i,t)$ Active power generation via CHP system connected to bus i at hour t(kW)
$H_{CHP}(i,t)$ Heat generation via the CHP system connected to bus i at hour t(kW)
$H_{Boiler}(i,t)$ Heat generation via the boiler connected to bus i at hour t(kW)
$Grid_{sell}(t)$ Purchased electricity by the network from the upstream network at hour t (kW)
$Grid_{buy}(t)$ Electricity sold to the upstream network by the network at hour t (kW)
$ILT(i,t)$ Involuntary load curtailment in bus i at hour t(kW)
$ILT_{NS}(i,t,NS)$ Involuntary load curtailment in bus i at hour t in scenario NS(kW)
$Pflow(l,t)$ Real power flow of line l at t hour t(kW)
$Pflow_{NS}(l,t,NS)$ Real power flow of line l at t hour t in scenario NS(kW)
$\delta_{NS,m}(l,t,NS)$,$\delta_{NS,n}(l,t,NS)$ Voltage angles of sending-end bus and receiving-end bus of line l in scenarioNS
$\delta_m(l,t)$, $\delta_n(l,t)$ Voltage angles of sending-end bus and receiving-end bus of line$l$

programming, quadratic programming, and mixed integer programming. Therefore, it is proposed to utilize Mix Integer Linear Programming (MILP) techniques in which there is no worry about the non-differentiability and the non-linear nature of the objective functions and constraints. Most of literature addresses the UC for power only generation and CHP systems. Some methods such as Lagrangian relaxation (LR) [4], Genetic Algorithm (GA) [5], Particle Swarm Optimization (PSO) [6], Branch and Bound (BB) [7],