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Impact of demand response resources on unit commitment and dispatch in a day-ahead electricity market ☆

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ABSTRACT

Demand response (DR) has recently become an important resource in both system operation and market operation. The focus of this paper is to investigate and quantify the cost impact of various demand response modelings on unit commitment and dispatch in a day-ahead market regime. We have used mixed integer programming unit commitment model, in the market operation framework. Day-ahead market is modeled with a typical test system. Our research results show that DR can exert downward pressure on electricity prices, causing significant implications on social welfare. Results from this work will help policy makers, resource planners, and market designers to make more informed decisions with the goal of better accommodating more demand response resources in the future.

Introduction

Nowadays, several emerging issues pose challenge to the traditional power system operation. Some of these issues include growing environmental threats, and limited system resources which force the system operators to operate their system closer to its limits, causing occasional price spikes in electricity markets. Increasing amount of variable renewable energy resources also increases the generation variability due to their uncertain output. These concerns motivated us to explore and investigate new ways of improving the efficient utilization of all available resources in power and market operations.

One of the resources that is drawing increasing attention is the demand response (DR). Demand response can be defined as any resource that has the capability to change or reduce the electricity consumption at a given time. The mode to change the electricity consumption can be instantaneous or pre-scheduled. Since DR is a demand side resource, in contrast to supply side resource, the key players of DR resources are those who consume, not supply, electricity. Typically, they are represented by residential, commercial, and industrial customers of electricity.

DR is becoming an integral part of the power system and market operational practice. Application of a DR program can provide better manageability to system operators, optimizing their position, and maximizing the revenue opportunities for DR providers. The inclusion of DR in conjunction with renewable energy, distributed generation, and plug-in hybrid electric vehicles will provide benefits to optimize the use of these resources and as a conclusion improve the efficiency of the system operation.

At the same time, the advances in communications, information systems, and computer technologies have opened up new opportunities to operate power system in a new way. A good example of that would be the automatic control of demand at the distribution level. The controllable demand becomes a very important source of flexibility which can be used to improve the system controllability, and which cannot easily be provided by conventional generators, due to several constraints, such as generator ramp rates. In a sense, the controllable demand can and should respond quite fast.

Under current market-clearing regime, the traditional generator scheduling or Unit Commitment (UC) and the Security-Constrained Unit Commitment (SCUC) programs deal only with fixed demand estimated by load forecasting process. Incorporating DR into these programs induces to a complicated objective function and creates additional constraints which must be dealt more carefully. At

☆ The views presented in this paper do not necessarily represent those of the PJM Interconnection.

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Nomenclature

t	index for simulation hours
b	index for cost curve segments
n	index for start-up cost curve
g	index for generation units
j	index for demands
k	index for demand blocks
T	total number of simulation hours
G	total number of thermal units
B	total number of segments for production cost curve
$Cp_{g,t}$	production cost for unit g at hour t \$/h
$Cup_{g,t}$	start-up cost for unit g at hour t \$
$p_{g,t}$	active generation for unit g at hour t MW
$r_{g,t}$	active reserve contribution of unit g at hour t MW
$\delta_{b,g,t}$	active generation for segment b, unit g, hour t MW
$u_{g,t}$	binary state variable for unit g, hour t
$s_{g,t}$	start-up variable for unit g, hour t
$h_{g,t}$	shut-down variable for unit g, hour t
θ	bus voltage angle
f	branch flows
$x,\ z$	penalty variables
Δ	corrective dispatch
π	shadow prices for the Network sub problem
$DB_{j,t}$	demand bid function value at demand j, hour t
$Bid_{k,j,t}$	demand bid value at block k, demand j, hour t \$/MW h
$d_{j,t}$	demand value for j, hour t MW
D_t	system demand at time t MW
R_t	system spinning reserve requirement at hour t MW
MU_g	minimum up time for unit g h
MD_g	minimum down time for unit g h
T_g^{off}	number of hours unit g has been off at $t = 0$ h
T_g^{on}	number of hours unit g has been on at $t = 0$ h
c_g	fixed cost for unit g \$/h
$F_{b,g}$	slope for segment b, unit g \$/MW h
$\overline{P}_g$	maximum capacity for unit m MW
$\underline{P}_g$	minimum capacity for unit m MW
$K_{n,g}$	cost for start-up cost step n, unit g \$/h
$\mathrm{Tr}_{b,g}$	active power limits, block b, unit g
RUL_g	ramp up limit, unit g MW
RDL_g	ramp down limit, unit g MW
$\underline{Y}_s$	susceptance matrix
$\overline{f}$	branch flow limits
$\mathbf{c}_x$	sub problem costs (set to one)
$CB_{k,j,t}$	demand cost value, block k, demand j, hour t \$
$MWB_{k,j,t}$	MW value for block k, demand j, hour t MW
$\overline{D}_{j,t}$	maximum demand value for demand j, hour t MW
$\underline{D}_{j,t}$	minimum demand value for demand j, hour t MW

minimum, the objective function and constraints have to be modified to correctly account for the unique characteristics of DR. Different formulations of objective functions and constraints can lead to different solutions, which can trigger different market system outcomes (MW, price schedules, and other subsequent system outcomes).

Federal Energy Regulatory Commission (FERC) [1] highlights areas of research related to DR and its inclusion into scheduling formulation. Proposed areas of research include the study of benefits, potential costs, cost recovery, rate design, and program marketing, payback horizons associated with DR programs. Other topics include analysis of the impact on the emission mitigation effects of DR, integration of DR with renewable energy, distributed generation, and plug-in hybrid electric vehicles (PHEVs), coordination of different DR programs, utility DR programs with RTO/ISO demand response programs for organized power markets.

In addition, the "USA National Action Plan" recognizes that for the United States to realize its full demand response potential, electricity customers must have access to, and a better understanding of, information about real-time or near-real-time energy prices. Better price information delivered more clearly will help potential demand response providers design market offerings, assist utilities in designing DR-encouraging rates, and help potential DR customers evaluate whether to participate in a demand response program.

We provide, as below, a brief review of literature on this important topic.

Market simulation approach [2] was used to quantify the variable impact of demand response on market performance, generation dispatch, transmission usage, environmental and other system effects. The work was done in light of planning and policy analysis studies. Implementation issues, related to large-scale systems over longer-term periods were also discussed.

In Ref. [3], although generation scheduling problem was considered as part of framework for incorporating demand response in a competitive market, the issue of unit commitment was ignored. Instead, it tried to solve economic dispatch problem only with the assumption that a generator is turned off when its output is zero.

It can be observed from Ref. [4] that the papers from the state of the art work treat generation in a simplified manner, disregarding short term operational constraints and demand response is not considered for short term simulations.

In the literature, several DLC (direct load control) algorithms have been developed to determine the optimal load control schedules of groups of domestic devices [5,6]. Most of them are based on linear programming [5,6,7,8], or dynamic programming [9,10], and tried to minimize peak load [5,6] or electricity production cost [5,9] over a certain time period.

Demand response, in combination with wind, can provide more cost-effective emission reductions, than just wind alone, using a case study based on Texas power system [11]. The authors found that while wind variability can increase the price, DR can be an alternative providing the opposite effect to help reduce that price volatility. Some recent work [12] was done to investigate the impact of price-based demand response on market clearing and LMP. The test system used in this work was too small to have any meaning. Similarly, the work in [13] investigated the effects of responsive load models on unit commitment in collaboration with demand-side resources. The author concluded that it is not possible to obtain the minimum cost for system using an unsuitable scheme of demand response programs or unrealistic model of responsive loads. Authors in [14,15] also solved the stochastic unit commitment problem with modeling of uncertain demand response. Integrating commercial demand response resources with unit commitment was also done in [16].

The aim of this paper is to analyze the utilization patterns of the DR resources from a system operation point of view, their impact on the operation of competitive markets, unit commitment solutions, and on market prices. Different types of DR models and methods are reviewed and the simulations are carried out on IEEE 118 bus system [17]. Based on the results, some recommendations are made regarding the efficient operation of power system and power market, with inclusion of DR resources.

The paper is organized as follows. We describe the general classifications of DR and various DR programs at RTO/ISOs in Section 'Demand response'. In Section 'Unit commitment problem