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Interconnection-wide hour-ahead scheduling in the presence of intermittent renewables and demand response: A surplus maximizing approach

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HIGHLIGHTS

- A new approach for electricity resource allocation that includes priceelastic loads.
- A new model of interconnection-scale scheduling that maximizes economic surplus.
- A demonstration of the scheduling method on the North America Western Interconnection.

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ABSTRACT

This paper describes a new approach for solving the multi-area electricity resource allocation problem when considering both intermittent renewables and demand response. The method determines the hourly inter-area export/import set that maximizes the interconnection (global) surplus satisfying transmission, generation and load constraints. The optimal inter-area transfer set effectively makes the electricity price uniform over the interconnection apart from constrained areas, which overall increases the consumer surplus more than it decreases the producer surplus. The method is computationally efficient and suitable for use in simulations that depend on optimal scheduling models. The method is demonstrated on a system that represents North America Western Interconnection for the planning year of 2024. Simulation results indicate that effective use of interties reduces the system operation cost substantially. Excluding demand response, both the unconstrained and the constrained scheduling solutions decrease the global production cost (and equivalently increase the global economic surplus) by \$12.30B and \$10.67B per year, respectively, when compared to the standalone case in which each control area relies only on its local supply resources. This cost saving is equal to 25% and 22% of the annual production cost. Including 5% demand response, the constrained solution decreases the annual production cost by \$10.70B, while increases the annual surplus by \$9.32B in comparison to the standalone case.

1. Introduction

Most jurisdictions in North America have adopted renewable energy portfolio policies as part of efforts to reduce greenhouse gas emissions. The inherent intermittency of renewables is the main challenge to the large-scale integration of these clean resources at high penetration levels. The traditional utility approach to generation variability is to operate reserve units, which are usually more costly and may increase emissions. Demand response is a zero-emission and potentially lower-cost alternative to the use of generation reserves. It also benefits the flexible load through payment for their services, and benefits all consumers through lowered electricity costs. The US Department of Energy has adopted a definition of demand response that is now widely recognized for its inclusiveness [1]: “load variations in response to changes in both financial incentives and/or reliability signals over time”.

The idea of including demand response in electricity markets is discussed in a large body of recent works. The impact of demand response integration on peak energy consumption, energy price

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Nomenclature

A	market state solution matrix
b	market condition vector
d	demand curve slope, in \$/(MW h·MW)
e	net export, in MW
f	transfer flow, in MW
p	price, in \$/MW h
p_{max}	must-serve load price, in \$/MW h
p_{min}	must-take generation price, in \$/MW h
q	quantity, in MW
s	supply curve slope, in \$/(MW h·MW)
x	market state vector
Y	connectivity matrix
α	degree of demand inelasticity
Δ	difference operator
ω	combined slope, in \$/(MW h·MW)
Ω	diagonal matrix of combined slopes

Subscripts

0	standalone
c	clearing
d	demand
p	price
q	quantity
r	responsive
s	supply
u	unresponsive
w	must-take

and emissions under load uncertainty is analyzed in [2]. A model of demand response participation in real-time markets to minimize the operation cost considering the load elasticity is formulated in [3]. The interaction between renewable intermittency and demand response in the market environment is investigated in [4].

Load fluctuations and renewable generation intermittency are generally not strongly correlated with each other over a large interconnected system that includes multiple balancing authorities [5]. As a result, the combined interconnection power fluctuations are smaller than the sum of the variations in individual balancing authorities. Neighbouring jurisdictions can take advantage of the geographical diversity of renewable resources within the system, and cooperate more effectively to mitigate the intermittency of renewable power generation. This cooperation, which is beneficial from both reliability and economic viewpoints, requires an enhanced transmission system, sometimes referred to as a "super-grid" [6]. A recent study of consolidation of balancing authorities in the US [7] showed that if planners moved away from a regionally divided electricity system to a national system using high-voltage direct-current transmission lines then the deployment of wind and solar power could reduce CO_2 emissions by up to 80% relative to 1990 levels, without an increase in electricity price.

Resource scheduling using locational marginal price (LMP) has been the foundation of modern electricity system operations since the early 1980s when it was first introduced [8]. The basic LMP solution was subsequently extended to perform security constrained economic dispatch (SCED) to satisfy operational constraints. This family of solutions has been deployed very successfully by transmission system operators [9]. However, the LMP formulation considers load to be essentially inelastic. Approaches to compensating demand response that allow consideration of price sensitive loads have been examined [10]. For policy-makers seeking to study the widespread development of renewable resources and the impact of demand response in system operation, the preferred LMP/SCED solution to the resource scheduling problem presents a significant barrier to adoption because the system models are typically constructed in a manner that assumes: (i) the system operation is dominated by supply resources with significant and relatively consistent fixed and variable cost components throughout an interconnected system, and (ii) demand is essentially inelastic and predictable. Solutions to the demand response problem include those proposed by the US Federal Energy Regulatory Commission [11]. Unfortunately, renewable resources such as wind and solar do not fulfill assumption (i), and short-term redispatchable demand does not conform well to assumption (ii).

A deep understanding of the interconnection-scale impact of demand response integration is difficult to achieve in the absence of accurate resource allocation models that properly consider the system-wide impact of demand response on locational energy price calculations and generation resource allocation. This is even more important for the case of large interconnected systems where mixed pricing mechanisms are extant, such as in the Western Electricity Coordinating Council (WECC). In the WECC some regions have fully developed energy markets and others do not, and multiple balancing authorities operate and interact through a myriad of bilateral contracts and other financial arrangements including some as obscure as the Columbia River Treaty [12]. In an effort to address these barriers and to study optimal operation of large-scale interconnections, we are motivated to find a more flexible and general model of the resource scheduling problem based on energy pricing. In the absence of price sensitive loads, the problem of unit commitment is to determine the hourly generation schedule in a way that minimizes the operational costs, which equivalently maximizes the economic surplus (social welfare) [13,14]. Therefore solving the traditional LMP problem is sufficient. However, when a significant amount of price sensitive loads is present, minimizing cost is no longer a satisfactory objective, and maximizing surplus is preferred [15], as described in Section 2. Surplus maximization for the unit commitment problem has been already formulated at the balancing authority level [16–18]. In the present work, we are interested in analyzing this problem at the interconnection level. More precisely, we seek a set of inter-area power transfers that maximizes the global surplus, which is defined as the sum of consumer and producer surpluses over all balancing authorities in an interconnection.

The optimal operation of the interconnection helps utilities produce electricity with a lower cost, integrate more intermittent renewables, and defer or cancel costly investments in grid infrastructure. Previous work [19] has shown the potential annual savings in production cost due to consolidation of balancing authorities ranges from 2.4% to 3.2%, considering transmission congestions. The full coppersheet consolidation of the WECC system provides an additional 1.4% improvement. However this study did not consider the impact of demand response on system resource allocation. Load management assists the WECC system operators in dealing with uncertainty in demand and intermittent resource output [20].

We consider one important reference to be the inelastic demand scenario in which the WECC system as a whole is operated in the most economically efficient manner. This scenario is unlikely because of various jurisdictional regulations, but it does provide an