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Optimal subhourly electricity resource dispatch under multiple price signals with high renewable generation availability

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HIGHLIGHTS

- A method to minimize the cost of subhourly dispatch of bulk electric power systems.
- Dispatch based on simultaneous use of energy and ramping costs yields significant savings.
- Savings from optimal dispatch increase as transmission constraints increase.
- Savings from optimal dispatch increase as variable generation increases.

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ABSTRACT

This paper proposes a system-wide optimal resource dispatch strategy that enables a shift from a primarily energy cost-based approach, to a strategy using simultaneous price signals for energy, power and ramping behavior. A formal method to compute the optimal sub-hourly power trajectory is derived for a system when the price of energy and ramping are both significant. Optimal control functions are obtained in both time and frequency domains, and a discrete-time solution suitable for periodic feedback control systems is presented. The method is applied to North America Western Interconnection for the planning year 2024. It is shown that an optimal dispatch strategy that simultaneously considers both the cost of energy and the cost of ramping leads to significant cost savings in systems with high levels of renewable generation: the savings exceed 25% of the total system operating cost for a 50% renewables scenario.

1. Introduction

The growth of renewable electricity generation resources is driven in part by climate-change mitigation policies that seek to reduce the long-term societal costs of continued dependence on fossil-based electricity generation and meet growing electric system load using lower cost resources. However, each class of renewable generation comes with one or more disadvantages that can limit the degree to which they may be effectively integrated into bulk system operations.

Hydro-electric generation has long been employed as a significant renewable electric energy and ramping resource. But climate change may jeopardize the magnitude and certainty with which the existing assets can meet demand [1,2]. Concerns about population displacement, habitat loss and fishery sustainability often limit the growth of new hydro-electric generation assets, placing additional constraints on new ramping response resources, such as requiring the use of additional reserves and ramping resources. Shifts in both load and hydro-electric generation potentially increase uncertainty in long term planning and further enhance the need for technological configurations that support operational flexibility [3].

Wind power has seen rapid growth, but concern about system reliability has limited the amount of wind generation that can be supported without additional planning and operational measures, such as committing more carbon-intensive firming resources [4]. Solar resources are also becoming increasingly available but the intermittency challenges are similar to those of wind. In addition, residential rooftop solar resources are challenging the classical utility revenue model [5]. They can cause voltage control issues in distribution systems [6], and in extreme cases can result in overgeneration [7]. Taken together these considerations have given rise to questions about the reliable, robust control and optimal operation of an increasingly complex bulk electricity system [8].

The conventional utility approach to addressing renewable generation variability is to allocate additional firm generation resources to

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Nomenclature

$\ddot{Q}$	ramping rate of change in MW/h^2
$\dot{Q}$	ramping in MW/h
$\dot{Q}^*$	discrete power at next time step in MW
$\dot{Q}_0$	initial ramping in MW/h
$\dot{Q}_T$	terminal ramping in MW/h
λ	Lagrange multiplier (excluding Q_z) in \$/MW·h
μ	Lagrange multiplier (including Q_z) in \$/MW·h
ω	square root of energy to ramping marginal price ratio in h^{-1}
A	a cost parameter (unit varies according to context).
a	marginal price of energy in \$/MW^2·h.
B	a cost parameter (unit varies according to context)
b	marginal price of power in \$/MW^2
C	a cost parameter (unit varies according to context)
c	marginal price of ramping in \$·h/MW^2
$C(t)$	cost over the time interval 0 to t in \$
C^*	cost associated with discrete time control in \$
C_{base}	cost associated with base case control in \$
D	a cost parameter (unit varies according to context)
$E(t)$	energy over the time interval 0 to t in MW·h
E_Δ	energy demand parameter in MW·h
E_T	energy over T in MW·h
$G(t,Q,\dot{Q})$	cost Lagrangian in \$
k	discrete time step in p.u.
$P(Q)$	power price function in \$/MW·h
$Q(t)$	power in MW
Q^*	discrete power in MW
Q_0	initial load in MW
Q_Δ	power demand parameter in MW
Q_E	scheduled load in MW
Q_T	terminal load in MW
Q_z	must-take generation in MW
$R(Q,\dot{Q})$	ramping price function in \$/MW
s	frequency domain complex variable in h^{-1}
T	interval terminating time in hours
t	time domain real variable in hours
	time step in seconds
\$100/MW h	system operating cost at 100 GW
\$B	billions of US dollars
\$M	millions of US dollars.
ISO	independent system operator
WECC	Western Electric Coordinating Council

replace all potentially non-firm renewables resources. These firm resources are typically fast-responding thermal fossil resources or hydro resources when and where available. For new renewable resources the impact of this approach is quantified as an intermittency factor, which discounts for instance the contribution of wind in addition to its capacity factor and limits the degree to which renewables can contribute to meeting peak demand [9]. However, the intermittency factor does not account for the ramping requirements created by potentially fast-changing renewable resources [10]. The need for fast-ramping resources discourages the dispatch of high-efficiency fossil and nuclear generation assets and can encourage reliance on low-efficiency fossil-fuel resources for regulation services and reserves [11].

One solution to overcoming the renewable generation variability at the bulk system level is to tie together a number of electric control areas into a "super-grid" so that they can share generation and reserve units through optimal scheduling of system interties [12]. In an interconnected system, the combined power fluctuations are smaller than the sum of the variations in individual control areas. Furthermore, fast-acting energy storage systems and demand response programs can provide required ancillary services such as real-time power balancing [13] and frequency regulation [14] if they are equipped with suitable control mechanisms. A competitive market framework in which energy resources participate to sell and buy ancillary service products can accelerate the transition to a high-renewable scenario by supporting the long-term economic sustainability of flexible resources.

Concerns about the financial sustainability of utilities under high level of renewables are also beginning to arise. The question is particularly challenging when one seeks solutions that explicitly maximize social welfare rather than simply minimizing production cost [15]. The growth of low-marginal cost renewable resources can lead one to expect utility revenues to decline to the point where they can no longer recover their long term average costs. However, this conclusion may be erroneous if one fails to consider both the impact of demand own-price elasticity, as well as the impact of load control automation on substitution elasticity. The latter type of demand response can significantly increase the total ramping resource on peak and decrease ramping resource scarcity. One option for replacing energy resource scarcity rent is increasing fixed payments. But this may lead to economic inefficiencies as well as an unraveling of the market-based mechanisms built so far. Another option is to enable payments based on ramping resource scarcity rent through existing markets for ancillary services. At the present time, the majority of resources continue to be dispatched based on the energy marginal cost merit order. But it is not unreasonable to consider how one might operate a system in which the energy price is near zero and resources are dispatched instead according the ramping cost merit order.

In the presence of high levels of variable generation, utilities and resource aggregators are faced with a particularly challenging problem. The scheduling of available resources is a co-optimization for allocating energy and ramping units, which may be priced very differently [16]. Under existing energy deregulation policies, there is usually a market in which energy producers compete to sell energy, and a separate market in which they compete to sell power ramping resources for flexibility. Producers get paid for their energy deliveries in the energy market and for power ramping flexibility in the flexibility market. However, today's dual-pricing mechanism is dominated by the energy markets, which drives generation resources to secure revenue primarily in the energy market, and only deliver residual ramping resources in the flexibility market. Poor access to energy markets might lead loads and storage to seek participation in flexibility markets while only revealing their elasticities to the energy market. This relegates loads and storage to only a marginal role in the overall operation of the system, which is the motivation for seeking policy solutions to improving their access to wholesale energy markets, such as FERC Orders 745 and 755.

1.1. Recent work

Work to address the problem of integrating ramping behavior into electricity pricing mechanisms originated with efforts to minimize total production cost. Generators are dispatched subject to ramping constraints in addition to system capacity reserve constraints, fuel and emission constraints, and network line flow limits [17]. If ramping costs are also revealed to the system operator, as in a fully regulated system, then the optimal power flow solution satisfies all the constraints under a fixed demand assumption [18]. However, this does not address the problem of flexible or interruptible demand. In field demonstrations the developers of transactive control explored solutions for a deregulated environment where the complete supply and demand curves were not revealed [19]. These solutions only addressed generation capacity, demand response capacity and line flow constraints. The solutions