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Assessing the economic value of co-optimized grid-scale energy storage investments in supporting high renewable portfolio standards

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HIGHLIGHTS

- We present a MILP to co-optimize generation, transmission, and storage investments.
- We find significant value in co-optimized storage via investment deferrals.
- Operational savings from bulk services are small relative to investment deferrals.
- Co-optimized energy storage significantly reduces prices associated with RPS.

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ABSTRACT

Worldwide, environmental regulations such as Renewable Portfolio Standards (RPSs) are being broadly adopted to promote renewable energy investments. With corresponding increases in renewable energy deployments, there is growing interest in grid-scale energy storage systems (ESS) to provide the flexibility needed to efficiently deliver renewable power to consumers. Our contribution in this paper is to introduce a unified generation, transmission, and bulk ESS expansion planning model subject to an RPS constraint, formulated as a two-stage stochastic mixed-integer linear program (MILP) optimization model, which we then use to study the impact of co-optimization and evaluate the economic interaction between investments in these three asset classes in achieving high renewable penetrations. We present numerical case studies using the 24-bus IEEE RTS-96 test system considering wind and solar as available renewable energy resources, and demonstrate that up to $180 million/yr in total cost savings can result from the co-optimization of all three assets, relative to a situation in which no ESS investment options are available. Surprisingly, we find that co-optimized bulk ESS investments provide significant economic value through investment deferrals in transmission and generation capacity, but very little savings in operational cost. Finally, we observe that planning transmission and generation infrastructure first and later optimizing ESS investments—as is common in industry—captures at most 1.7% ($3 million/yr) of the savings that result from co-optimizing all assets simultaneously.

1. Introduction

The electricity industry is undergoing significant transformation due to increasing renewable generation. At the end of 2014, renewables represented nearly 60% of global generation capacity additions, reaching a total installed capacity of 1712 GW [1]. To continue reducing emissions and promoting investment in new renewable generation (from wind and solar), environmental regulators are increasingly relying on new integration technologies, such as energy storage systems (ESS), and incentives, such as Renewable Portfolio Standards (RPSs), Feed-In Tariffs (FITs), and Investment and Production Tax Credits (ITCs and PTCs) [2]. To date, more than 150 countries have implemented renewable policy targets [1]. In this article, we focus on the interaction between RPS-type policies and generation, transmission, and ESS investments; however, our model can be extended to study interactions with other environmental policies.

In contrast to other incentives that pay a fixed price for renewable generation or investment, an RPS incentivizes generators

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within a region to produce a minimum fraction of electricity from qualifying renewable resources via a market mechanism. Under an RPS, qualifying renewable energy is linked to a tradeable Renewable Energy Certificate (REC), with entities meeting the mandate by holding the equivalent number of RECs. A market provides flexibility for participants to trade these RECs to meet RPS requirements, creating economic incentives for innovative and cost-effective renewable production.

While there is no federal-level RPS in the US, 33 states have introduced individual mandates ranging from as low as 10% to as high as 50% (California) and 100% (Hawaii) [2,3]. Other countries that have similar binding renewable mandates with tradeable RECs include Australia (20% by 2020), Chile (20% by 2025), Denmark (50% by 2020), France (27% by 2020), Japan (20% by 2030), Malaysia (15% by 2050), Spain (38.1% by 2020), South Africa (9% by 2030), and Ukraine (20% by 2030) [1]. Across these countries, REC markets can vary significantly in the definition of obligations and eligibility, resource-specific set-asides and multipliers, cost caps, and available flexibility mechanisms (e.g., banking and borrowing of RECs) [4,5]. In the US, several studies find that states that have implemented this policy effectively increased renewable investment relative to neighboring states without RPS goals [5,6]. Other international studies find that RPSs are either about the same or marginally less effective than alternatives such as FITs [7–9].

With increasingly stringent RPS requirements come integration challenges that must be accounted for when making planning decisions. In particular, resource intermittency for wind and solar deployment can lead to over-generation and steep ramps during peak hours, as illustrated by the California ISO's now-famous "duck curve" plot for net system demand [10]. To balance intermittent generation, operators will need to cycle thermal generators more often and deploy new flexibility resources, such as demand-side management, sub-hourly dispatch, and regional coordination. Several studies argue that these operational resources represent the best value for renewables integration targets below 50% [11,12]; however, it is clear that operational changes alone cannot achieve the balancing needed at very high RPS levels and that investment into new network infrastructure will need to be considered.

While pumped-hydro storage remains one of the lowest cost bulk ESS technologies in terms of MW h stored, faster-responding technologies such as flywheels, super capacitors, and batteries (e.g., lithium-ion, vanadium redox flow, zinc-air, and sodium-sulfur) can provide power and ancillary services that reinforce grid stability [13]. Third party investment has also been boosted by Federal Energy Regulatory Commission Order No. 755 and subsequent Order No. 784, which require creation of markets for "fast and accurate" frequency regulation services for third party merchants, which is favorable for fast-responding ESS technologies [14,15]. In this paper, however, we focus specifically on bulk energy storage services, which include load shifting, peak shaving, and generation and transmission investment deferrals [16].

Currently, the PJM Interconnection (US) has invested in over 100 MW of battery energy storage for frequency regulation, while the Sistema Interconectado del Norte Grande (Chile) has installed over 30 MW for similar use [17]. Further, the California Public Utilities Commission has mandated that the state's three major utilities invest in a combined 1325 MW of energy storage capacity by 2020 [18]. The specific justification for this mandate is that energy storage can improve the cost-effectiveness of integrating increasing amounts of renewables to meet the state's RPS goals—and with lower carbon emissions [19]—through (1) load shifting; (2) generation, transmission, and distribution support and upgrade deferrals; and (3) ancillary grid services [20].

While lawmakers and system planners agree that ESS investment is key to achieving high RPS targets, we find that no existing studies focus on the co-optimization of generation, transmission, and ESS investments in the face of such requirements. To address this, this paper analyzes the economic interaction between investments in these three asset categories on a synthetic transmission network for a wide range of RPS targets. We formulate our model as a two-stage stochastic mixed-integer linear program (MILP) based on standard economic dispatch and transmission expansion planning models, coupled with a generic ESS operations model. We then obtain insight into the value of ESS investments relative to other assets in achieving RPS compliance in a cost-effective manner.

Using a 24-bus test case we find that co-optimizing generation, transmission, and ESS investments can save up to \$180 million/yr or 9.1% of total system cost with respect to a co-optimization model that does not consider ESS. Furthermore, we demonstrate significantly lower benefits when planning ESS investments after generation and transmission infrastructure has already been selected versus our fully co-optimized solution. These savings are of (at most) \$3 million/yr instead of \$180 million/yr. Although the magnitude of these savings is not general and depends on the specific application, our results highlight that:

a) the savings that result from considering ESS investments can be significant and are primarily a result of deferrals in new generation and transmission infrastructure,
b) optimizing ESS investments after planning generation and transmission infrastructure only captures energy arbitrage value, which is a small percentage of the potential economic benefits of ESS in meeting RPS policies, and
c) co-optimization models and/or more coordination between transmission planners and investors in generation and ESS could reduce the cost of meeting RPS policies.

The rest of the paper is organized as follows. Section 2 summarizes the relevant literature on generation, transmission, and ESS investment planning and on co-optimization models. In Section 3, we propose a planning model that co-optimizes generation, transmission, and ESS investments. Section 4 describes the test case and data assumptions. In Section 5, we present and analyze our numerical experiments. Finally, in Section 6, we conclude and discuss the policy implications.

2. Literature review

Optimal generation and transmission investment planning has received increasing attention in the last two decades [21,22]. Transmission planning in particular is a challenging problem given the combinatorial nature of the problem and the size of real-world transmission networks. Some proposed models include linearized DC mixed-integer linear formulations [23,24], non-linear models with DC power flows that take into account transmission losses [25], and non-linear models with AC power flows [26,27]. In the context of power system economics, previous studies have analyzed the interaction between RPS goals, the representation of transmission constraints, and the "lumpiness" of real transmission investments, finding significant deviations in decision-making when the physical and economic constraints are considered [28–30]. In our research, we work with a linearized DC formulation, which provides a good balance between solution accuracy and computational complexity.

The majority of the investment planning models reported in the academic literature seek to minimize total system cost, assuming that the planning is conducted by a vertically integrated utility. However, there is another class of planning tools that falls into the category of equilibrium models. These include generation equilibrium [31], transmission-generation leader-follower schemes