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Power system balancing for deep decarbonization of the electricity sector

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HIGHLIGHTS

- System balancing needs for deep decarbonization are dependent on technology mix.
- Solar PV deployment is the main driver of battery storage deployment.
- Concentrating solar power with thermal storage is valuable for its dispatchability.
- Wind exhibits seasonal variation, requiring storage with large energy subcomponent.
- Low-cost solar PV and batteries can mitigate the cost of climate change mitigation.

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ABSTRACT

We explore the operations, balancing requirements, and costs of the Western Electricity Coordinating Council power system under a stringent greenhouse gas emission reduction target. We include sensitivities for technology costs and availability, fuel prices and emissions, and demand profile. Meeting an emissions target of 85% below 1990 levels is feasible across a range of assumptions, but the cost of achieving the goal and the technology mix are uncertain. Deployment of solar photovoltaics is the main driver of storage deployment: the diurnal periodicity of solar energy availability results in opportunities for daily arbitrage that storage technologies with several hours of duration are well suited to provide. Wind output exhibits seasonal variations and requires storage with a large energy subcomponent to avoid curtailment. The combination of low-cost solar technology and advanced battery technology can provide substantial savings through 2050, greatly mitigating the cost of climate change mitigation. Policy goals for storage deployment should be based on the function storage will play on the grid and therefore incorporate both the power rating and duration of the storage system. These goals should be set as part of overall portfolio development, as system flexibility needs will vary with the grid mix.

1. Introduction

Deep decarbonization of the electric power sector, combined with electrification of most end-uses of natural gas and oil, is indispensable to achieving climate change mitigation [1]. Renewable energy technologies such as wind and solar can contribute to electricity decarbonization. However, these resources have variable and uncertain power output. The need to balance them poses operational challenges and increases grid integration costs. A large number of integration studies have been conducted for regions in the United States and Europe, exploring the operational impacts and integration costs of intermittent energy sources [2,3]. These studies assume pre-specified deployment levels and locations of wind and solar power plants and take the rest of the grid as fixed, investigating only a limited number of fleet configurations for generation, transmission, and storage. Here we use a capacity-planning model for the economic evaluation of intermittent renewables and a range of balancing solutions. We include operational detail in an investment-modeling framework to make it possible to evaluate the economics of a range of system flexibility resources. We focus in particular on the need for and role of electricity storage in deeply decarbonized power systems.

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Electricity storage is one way to balance electricity demand and supply in electricity systems with deep penetration levels of wind and solar. Modeling the costs and benefits of storage technologies has generally taken one of two approaches: (1) use of market price data to determine the revenue that would be available to a storage project [4–7] or (2) use of production cost simulation models of the system with and without storage to determine how the availability of storage affects system operational costs [8,9].

A weakness of the first approach is that storage participation in the energy market will affect market prices by increasing demand during times when the storage is charging, thus raising the market price, and increasing supply during times when the storage is discharging, thus lowering the price. Pre-determined market prices therefore provide a reasonable approximation for the revenue stream available to the marginal storage unit, but become increasingly inaccurate as additional storage is added to the fleet or other components of the system are changed.

The second approach explores the difference in operational costs between systems with and without storage. A weakness of this approach is that it does not directly consider capital costs and potential savings from avoided investment in non-storage infrastructure. After the production cost model is run, the operational cost savings provided by storage may be compared to its capital cost to determine whether the benefit to the system would justify investment in storage. However, the rest of the system is held as fixed, so this approach does not provide information on how other generation and transmission infrastructure should be deployed and how the grid should be developed to minimize system cost as demand, technologies, and policies change. Most storage analyses to date do not allow for transmission or other sources of flexibility to be built as an alternative to storage to meet integration requirements, thus not considering the possible trade-offs or synergies among these flexibility options. These interdependencies become increasingly important as more variable renewable energy is deployed.

Capacity-planning models like SWITCH [10,11] and the Renewable Energy Deployment System (ReEDS) [12,13] offer an additional approach to examining the role of storage in grids with low levels of greenhouse gas (GHG) emissions. Their purpose is to explore how total system cost (capital, fixed, and variable costs) can be minimized, and to co-optimize storage deployment and investment in other system infrastructure. As intermittent renewable generation achieves higher penetration levels, integration alternatives such as transmission expansion, fast-ramping generation, storage, and demand response ought to be considered and compared in a single framework. We have incorporated operational detail into the SWITCH long-term capacity-planning model to allow for more accurate economic evaluation of intermittent renewables, storage technologies, and other integration alternatives [14,15]. Wind and solar generation technologies have low variable costs but require investment in capital-intensive infrastructure capacity, so employing capacity-expansion models can aid understanding of and planning for the most cost-effective resource combinations as the power system evolves

2. Methods

2.1. Model

We use the SWITCH model to study the synchronous region of the Western Electricity Coordinating Council (WECC). WECC covers eleven western U.S. states, two Canadian provinces, and northern Baja California, Mexico. The model is run as a linear program whose objective function is to minimize the cost of meeting projected electricity demand with existing and new generation, storage, and transmission between present day and a future year of interest. The optimization is subject to planning reserve margin, operating reserves, resource availability, operational, and policy constraints. The WECC is divided into fifty "load zones" between which new transmission can be built. We include geographic detail on the locations of potential future power plants and transmission lines. The optimization decides whether to operate or retire existing grid assets, can install new conventional generation in each load zone, chooses among thousands of possible wind and solar sites, and can build transmission lines between load zones. In order to account for correlations between demand and renewable generation, the model uses time-synchronized hourly load data and site-specific intermittent renewable generation data to determine least-cost investment in and hourly dispatch of generation, transmission, and storage. The results presented here are based on an investment optimization that includes 600 h and on a subsequent dispatch verification that includes 8760 h.

The version of the SWITCH model used here offers detailed treatment of system operations in a long-term capacity-planning model of a large geographic region. For this study, we have implemented a novel two-variable treatment of storage: investment decisions are made endogenously for both the capacity of the power subcomponent of storage (the maximum rate at which energy can be released) and its energy subcomponent (the total amount of energy that can be stored) [16]. The model can therefore determine the optimal size of storage devices for a given cost structure, as many types of energy storage technologies exist with different power ratings and discharge times [17–19]. This treatment of storage is an enhancement over our prior work as well as over other capacity-expansion and production cost simulation models, in which the sizing of electricity storage is a model input rather than an endogenous variable. We have also implemented the ability to determine how to optimally release energy from concentrating solar power (CSP) with thermal energy storage (TES) as an endogenous variable in the SWITCH investment optimization. The complete model formulation is available in the Supplementary Material.

2.2. Data and scenarios

We use SWITCH to explore the effect of various sources of uncertainty on storage deployment and overall system development between present day and 2050 in the WECC under strict decarbonization constraints. No scenario is intended as a forecast of future system development: conclusions are based on comparisons across scenarios that point to drivers of system dynamics and the relative importance of different sources of uncertainty.

In all scenarios, the power system achieves GHG emissions levels of 85% below 1990 emissions by 2050. We assume a single GHG target for the whole WECC region. Our goal is to understand the flexibility requirements – and in particular the role of storage – in such systems. In the *Reference* scenario, we assume that neither nuclear plants nor fossil fuel plants with carbon capture and sequestration (CCS) will be built through 2050. The focus is on systems in which low-GHG baseload technologies are not available and intermittent renewable technologies are the main source of GHG-free electricity. Biomass fuel is assumed not to be available to the electricity sector but is instead used for transportation purposes [20,21] further limiting the availability of carbon-free baseload. The potential for bio energy carbon capture and sequestration (BECCS) and negative emissions from such plants [22] is not explored here. Very little technological progress is assumed and costs for most technologies are modeled as constant between present day and 2050. Exceptions include decreases in the capital cost of solar PV, concentrated solar power (CSP), and batteries, but these reductions are modest.