Energy storage for backup power castries

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a, The average daily number of freight trains travelling from each state in the contiguous United States into each grid operating region, or ISO. The width of the grey line increases with the number of daily freight trains. Most ISOs already have daily trains moving between them; for ISOs without direct connections, many have shared secondary connections (for example, California and New York, with their own ISOs, are connected by Illinois). b, Average estimated time to move trains between ISOs; including scheduling time, moving trains between ISOs would probably take 1-6 days. The red lines represent the boundaries of each ISO. The blue shading depicts the estimated travel time to each ISO from each state. Basemaps provided by the US Census Bureau79.

For RMES to be feasible in the power sector, three conditions must be met. First, as with transmission lines, high-impact, low-frequency grid stressors must occur at non-coincident times between operating regions. This pattern enables the same resource to be shared across both regions, rather than requiring each region to retain its own capacity. Unlike transmission lines, RMES cannot move power instantaneously but rather would take 1-6 days to arrive from another region. A second condition therefore is that grid stressors must be separated by enough time to move RMES resources between regions. Third, these events must be predictable, with sufficient lead time to schedule and execute RMES shipments.

As the value of transmission lines depends on price separation between regions (that is, limited supply in one region and excess supply in another), we use transmission valuation methods to assess the spatial coincidence of major grid stressors17. Using LMPs from 2010 to 2021, we calculate the value of a transmission line between each unique combination of two price nodes, both between different ISOs and within a single ISO. We find that 17-25% of the value of transmission connections is concentrated in 1% of the total hours it could be used (Fig. 2b), confirming there is considerable value in moving power between regions during the lowest-frequency, highest-impact events.

Even if such events are separated by ample time, they must also be reasonably predictable for RMES to be valuable. We examine the predictability of three types of historical event that have required excess generation capacity: extreme weather emergencies, major price spikes caused by supply-demand imbalances and annual peak-demand events.

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Emergency events can sometimes be predicted several days in advance. Two recent emergencies, the 2020 California blackout and 2021 Texas winter storm, had three and eight days of notice, respectively20,42--well over the amount of time necessary for RMES scheduling and shipment. Seasonal and annual tight supply conditions can also be anticipated days or weeks in advance. To assess the feasibility of RMES to serve these periods, we estimate event predictability in two ways: (1) using day-ahead market prices as a proxy for tight supply predictability within one day of the event and (2) using gross load (that is, total electricity demand before netting out renewable generation) forecasts within 2-7 days of the event.

Annual day-ahead price spikes align with real-time price spikes over 90% of the time, suggesting high-impact events can be predicted with near certainty one day before they occur41. Thus RMES located within one day of a load centre could feasibly serve high-impact events using the day-ahead market as a commitment signal.

To assess the predictability of events 2-7 days away, we rely on gross load forecasts. Using data from 2010 to 202043, we calculate the difference between predicted and actual loads for the top 10% of load hours of the year. On average, forecast load is within 5% of actual load (Fig. 3). The relatively low forecast error across regions suggests that RMES could effectively be summoned across regions to serve high-impact events. That actual forecasting techniques are much more accurate than gross load forecasts should lend further confidence in RMES.

For all regions, the mean forecast error for 1-7 days ahead is below 5%, represented by the solid lines in each operating region. The shaded intervals around the solid lines represent one standard deviation from the mean forecast error. For regions except CAISO, the standard deviation of forecast error is approximately 5-10%, depending on region and number of days ahead, represented by the larger polygons in each market. CAISO has a larger standard deviation, perhaps owing to its high penetration of behind-the-meter renewable generation; its upper bound of forecast error is about 20%, one week in advance.

Figures 4 and 5 illustrate the potential cost savings from leveraging RMES to maintain grid reliability as compared to the two strategies above. Compared to stationary battery storage (Strategy (1)), RMES is more economical for low-frequency events when the distance between regions is small (Fig. 4a). For example, if RMES travels a total of 400 km between regions, it is more economical than stationary batteries when the resources are called upon <2% per region annually. RMES is also more economical than transmission investment (Strategy (2)) for low-frequency events, but, unlike stationary capacity, the cost-effectiveness of RMES grows compared to transmission as the distance between regions increases (Fig. 4b).

The unpredictability and immense impact of extreme events challenges system planners who are struggling to prepare as these events become more frequent and severe10,45,46. Though the cost of power interruptions during these events is estimated to range from US$360 MWh-1 to $300,000 MWh-1, their variability and spatial and temporal uncertainty pose financial and logistical challenges to typical grid reliability and resilience approaches47,48,49,50. Due to these challenges that extreme events pose, the Federal Energy

Regulatory Commission (FERC) does not yet have effective strategies for addressing them, instead proposing a "case-by-case" approach45.

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