# Evaluating the Technology Design Space for Long-Duration Energy Storage and Role in Deep Decarbonization of Power Systems

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## ABSTRACT

We evaluate the role of long duration energy storage (LDES) in decarbonized electricity systems and identify cost and efficiency performance necessary for LDES to reduce electricity costs and displace firm low-carbon generation. We find that energy storage capacity cost and discharge efficiency are the most important performance parameters. Charge/discharge power cost and charge efficiency play secondary roles. Energy capacity costs must be $\leq$\$20/kWh to reduce electricity costs $\geq$10%. With current electricity demand profiles, energy capacity costs $\leq$\$10/kWh are required to fully displace nuclear power; costs must be $\leq$\$1/kWh to fully displace natural gas w/carbon capture and sequestration or combustion of hydrogen (or similar fuels). Electrification of heating, transportation, and other end-uses in a northern-latitude context makes full displacement of firm generation more challenging and requires performance combinations unlikely to be feasible with known LDES technologies. Finally, LDES systems with the greatest impact on electricity cost and firm generation have storage durations exceeding 100 hours.

## Introduction

To achieve net-zero greenhouse gas emissions in the electric power sector cost effectively, some combination of the following technological solutions must be employed to manage long-duration imbalances in variable renewable energy (VRE) supply and electricity demand: (1) firm low-carbon generation technologies (e.g. nuclear, fossil fuels with carbon capture and storage (CCS), bioenergy, geothermal, or hydrogen and other fuels produced from low-carbon processes) can substitute for $CO_2$-emitting firm resources (coal and natural gas plants)[1]; (2) negative emissions technologies can be employed to offset $CO_2$ emissions from fossil fueled firm resources[2]; (3) transmission network expansion can increase the balancing area to cover large geographic regions and exploit spatio-temporal variations in weather and VRE resource availability;[3] and/or (4) energy storage can be employed to smooth out imbalances in VRE supply and electricity demand and substitute for firm resources. Firm resources are dispatchable electricity generation technologies that can produce energy on demand, any time of year, for any length of time, and thus exclude weather-dependent resources and energy-constrained or limited duration resources such as energy storage or demand flexibility.[1]

In scenarios that rely exclusively on the third and fourth strategies (VRE and storage), recent work has demonstrated that required wind, solar, and energy storage capacity increases rapidly after VRE energy shares exceeds ~80% of annual energy demand[4] or when strict $CO_2$ emission limits (e.g., below $\sim$50 $kgCO_2$/MWh) restrict the use of coal or gas-fired generation and force VRE shares above this level[1,5]. Sepulveda et al.[1] demonstrated that relying only on lithium ion (Li-ion) batteries (or other electrochemical storage options with similar cost and duration characteristics) to augment VRE capacity is not a cost-effective strategy for decarbonizing power systems. In contrast, including at least one firm low-carbon generation technology in the capacity mix lowered the cost of fully-decarbonized (zero-emission) electricity systems by 10-62% across a range of scenarios.

Other work has confirmed the insufficiency of Li-ion battery storage with typical storage durations of up to 10 hours and energy capacity costs in the 100s of \$/kWh[6], while suggesting that energy storage technologies with longer storage durations, lower energy storage capacity costs, and the ability to decouple power and energy capacity scaling could enable cost-effective electricity system decarbonization with all energy supplied by VRE[7,8]. Although Li-ion batteries can technically sustain output for longer periods by reducing discharge rates (de-rating discharge capacity relative to energy storage capacity), the relatively high cost per kWh of additional storage capacity and the limited ability to decoupling power and energy capacity costs make Li-ion batteries uneconomic as a long duration storage option[9]. Here we use the term "long duration energy storage" (LDES) to refer to various technologies that are expected to be *both technically and economically* suitable to cycle the marginal (or least utilized increment of) energy storage capacity infrequently and store energy in sufficient amounts to sustain electricity production during discharge over periods of days or weeks[10,11].

The potential for LDES technologies to enable higher penetration of low-cost wind and solar resources and help reduce the cost of decarbonized power systems has led to a wave of new research and development supported by private investors and government institutions[9,10,12]. The Duration Addition to Electricity Storage (DAYS) program at the Department of Energy's Advanced Research Projects Agency – Energy (ARPA-E)[10] directly supports development of LDES systems with (i) duration (maximum constant operation at rated discharge power capacity) between 10 hours and 100 hours; (ii) power capacity cost (investment associated with charge and discharge power capacity) below \$1,000/kW; and (iii) energy capacity cost (investment associated with energy storage capacity) below \$100/kWh, with a focus on the \$5-20/kWh range. Ziegler et al.[13] consider wind/solar and storage at the individual facility level and assess cost and duration requirements to produce a consistent "baseload" power output. They conclude that a combination of power and energy capacity costs of \$1,000/kW and \$20/kWh and a duration of 100 hours is sufficient to enable steady power output 100% of the time, and that \$700/kW and \$150/kWh and 40 hours duration could deliver baseload electricity for 95% of the time. Albertus et al.[11] argue that for high penetration of VRE generation ($\geq$ 90%), LDES systems with durations greater than 100 hours will be needed, with energy capacity cost below \$40/kWh and power capacity cost in the range of \$500-1000/kW.

LDES encompasses a diverse range of technologies, including electrochemical (e.g., low-cost flow batteries[14] or aqueous metal-air batteries[15]), chemical (e.g., production, storage, and oxidation or combustion of electrolytic hydrogen, known as "power-to-gas-to-power"[16,17]), thermal (e.g. sensible or latent heat storage[18,19]), and mechanical options (e.g., compressed air or pumped hydroelectric storage[20]). These technologies are at various stages of development and deployment and present different future cost projections, target efficiencies, and system architectures. Some are geographically constrained (e.g., geological hydrogen or compressed air energy storage), some permit scaling of energy capacity to be decoupled from power capacity (e.g. flow batteries), and some can scale charging and discharging power levels independently and also have different charge and discharge efficiencies (e.g., thermal storage and power-to-gas-to-power).

Given the wide range of different technologies, cost components and projections, and performance options, a comprehensive assessment of the impact of different combinations of LDES design parameters on the overall economics of deeply decarbonized power systems is needed. Among the unanswered questions that will be explored in this work: (i) how do different combinations of LDES design parameters affect LDES deployment rates and the average cost of electricity in decarbonized power systems; (ii) how does LDES (in combination with VRE generation) interact and compete with (substitute for) various firm low-carbon generation technologies and Li-ion batteries; and (iii) what are the most attractive/competitive architectures of LDES systems?

To answer these questions, this work employs an electricity system capacity expansion optimization model with high temporal resolution (8,760 hours) and detailed operating decisions and constraints[21] and performs extensive parametric analysis to evaluate, at the regional power system level, various combinations of five cost and efficiency parameters that span the range of likely performance characteristics of the candidate LDES technologies. These parameters include: (i) charge power capacity cost ($/kW); (ii) discharge power capacity cost ($/kW); (iii) energy storage capacity cost ($/kWh), which is measured in the units of the energy storage medium; (iv) charge efficiency (%); and (v) discharge efficiency (%). All capacity costs are on a fully installed basis, while charge and discharge efficiencies are assumed to be invariant with discharge or charge rate. Charge and discharge power capacity costs are based on AC power injected or withdrawn from the grid and assumes inclusion of grid interconnection costs. Because energy capacity and power capacities are independently sized based on the above defined cost parameters, storage "duration", representing the numbers of hours operation at peak discharge, is a dependent parameter that is a model output rather than an input (see (1a)). We collectively refer to the range of possible combinations of these five parameters as the LDES “technology design space” (see Table 3), and we model a total of 1,280 discrete combinations of these cost and efficiency parameters encompassing performance levels that are consistent with projections for existing LDES technologies found in academic peer-reviewed studies (see Table 2 and Fig. SI-1) as well as domains that are currently infeasible but that could be the focus of technology development efforts in the future. Note that while we present the projected performance regions for existing LDES technologies as simple boxes for plotting in Fig SI-1, not all points within the plotted areas may be simultaneously achievable due in particular to trade-offs between power capital costs and efficiency (e.g., the regions of lowest projected power cost and highest projected round-trip efficiency may not be practically achievable for all technologies). The long-run system-level optimization methods used herein are important to capture the declining marginal value of all resources and their resulting least-cost equilibrium penetration levels[22].

Furthermore, we evaluate the technology design space for LDES in multiple power system contexts encompassing different wind, solar, and demand characteristics and different assumptions regarding the availability of firm low-carbon technologies. This includes both a system with weather and demand conditions typical of New England and a system with weather and demand typical of Texas, referred to herein as the Northern System and Southern System, respectively. We also model demand profiles based on historical demand patterns (for both regional systems) as well as those based on high levels of electrification of transportation, heating, and industrial energy demands (modeled for the Northern System only). Additionally , we test sensitives to differences in wind, solar, and battery costs, and we test sensitivity of results to historically higher/lower than average wind and solar capacity factor weather years in the Northern System. We investigate the value of LDES in conjunction with three different firm low-carbon generation technologies – nuclear power, natural gas plants with CCS, and hydrogen combustion power plants – selected to span the range from high fixed/low variable costs to low fixed/high variable costs. We parameterize the hydrogen combustion plants using assumptions for the cost of hydrogen derived from natural gas reforming with CCS ( “blue $H_2$”), although this resource could represent any power plant burning a zero or near-zero carbon fuel with similar costs ($\sim$\$15 per million BTU). In total, we evaluate the full LDES technology design space in 14 different scenarios (Table 4) for a total of 17,920 distinct cases. See Methods below for further detail on experimental design and assumptions.

We find that energy storage capacity cost and discharge efficiency are the most important LDES performance parameters, with charge/discharge capacity cost and charge efficiency of secondary importance. Energy capacity cost must fall below \$20/kWh (with sufficient efficiency and power capacity cost performance) for LDES technologies to reduce total carbon-free electricity system costs by $\geq 10\%$. We observe a maximum of a 50% reduction in total system costs across the full technology design space considered, although the maximum reduction is limited to 40% within the combination of cost and performance parameters likely to be achieved by known LDES technologies. For LDES to fully displace firm low-carbon generation, an energy storage capacity cost of $\leq$\$10/kWh is required for the least competitive firm technology considered (nuclear). Energy capacity costs $\leq$\$1/kWh as well as a combination of very low power costs and high efficiencies are required to displace the more competitive firm technologies (natural gas w/CCS and hydrogen combustion turbines). We also find that high degrees of transportation and heating electrification in a northern-latitude power system makes full displacement of firm generation more challenging, requiring combinations of cost and efficiency performance that are infeasible with known LDES technologies. Finally, in cases with the greatest displacement of firm generation and the greatest system cost declines due to LDES, optimal storage discharge durations fall between 100-650 hours ($\approx 4-27$ days).

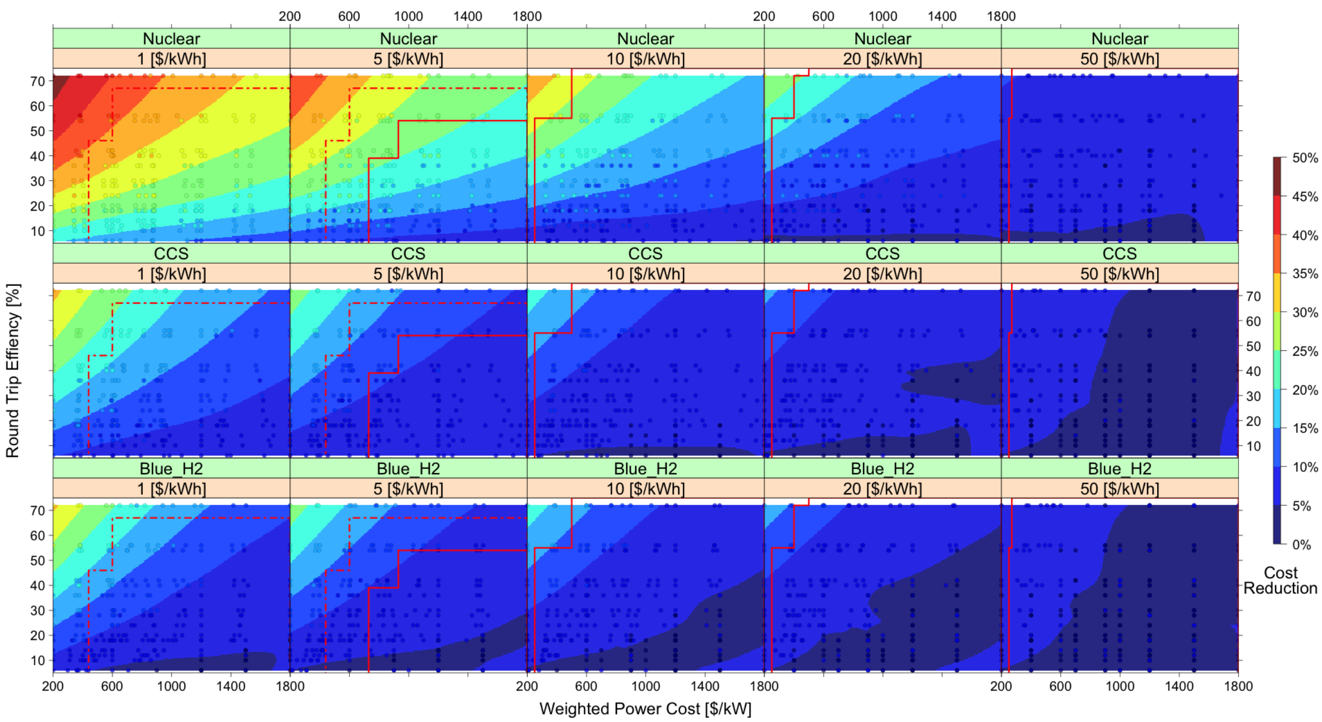
# Results

## System Value of LDES Technologies

We define the “system value” of a technology as the reduction in total electricity system cost that results from adding the new technology as an additional resource option in the capacity expansion framework. Since our analysis includes many different discrete combinations of cost and efficiency performance across the broad LDES design space, we determine system value by calculating the percentage reduction in annualized electricity system cost for a given case with LDES relative to the corresponding reference case without LDES but with all other model parameters identical (see Supplementary Table SI-1).

Figure 1 shows the system value of LDES as a function of the LDES energy storage capacity cost (\$/kWh, referred to subsequently as energy capacity cost for brevity), the weighted power capacity cost (\$/kW; see Eq. (1c) in Methods section for derivation), and the round-trip efficiency (RTE) for the Northern System and for the three different firm low-carbon technologies modeled. Supplementary Figure SI-3 shows LDES system value results for the Southern System. In these figures, the shaded regions are colored differently for each 5% increment in electricity system cost reduction, starting from a 0-5% cost reduction up to a 45-50% cost reduction (the maximum value seen in all 17,920 cases). The colored dots in these figures correspond to discrete cases and their color shading also indicates percent cost reduction on the same color scale. The shaded regions correspond to a smooth surface calculated using the LOESS method with a functional form $z \sim x * y$ where $z$ corresponds to the system value of LDES, $x$ corresponds to the LDES weighted power capacity cost, and $y$ corresponds to the LDES round-trip efficiency. Figures SI-27 to SI-35 also present results for system cost reduction in the original 5-dimensional space for energy capacity costs of $1-10/kWh.

Figures 1 and SI-3 indicate that reductions in energy capacity cost (columns going from right to left) are the most significant driver of LDES value, followed by increases in round-trip efficiency (y-axis from bottom to top on each subplot), followed by reductions in weighted power capacity cost (x-axis going from right to left on each subplot). A regression analysis reported in Table 1 also confirms the relative importance of these parameters, as discussed further below.




Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in system costs. "Future feasible regions" for known LDES technologies from Figure SI-1 are plotted to the right of the dash-dotted lines (geographically constrained) and solid lines (geographically unconstrained) for each row. Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total annualized system costs for the reference cases (in USD per MWh) are as follows: nuclear - $74.01; gas w/CCS - $57.20; Blue $H_2$ - $56.02.

**Figure 1.** Northern System: Percentage Reduction in System Cost for LDES Parameter Combination Compared to Reference Cases (Scenarios 4-6 in Table 4)

Comparing Figures 1 and SI-3 reveals that the two geographic regions exhibit very similar behaviors for the value of LDES as a function of the technology design space parameters. At the same time, the figures show that the ability of LDES to deliver value to the system depends significantly on which firm low-carbon technology is available (also confirmed by Table 1). For the same combination of LDES design space parameters, LDES delivers greater system value for cases with nuclear power as the only available firm low-carbon resource than for cases with gas w/CCS or hydrogen combustion ("Blue $H_2$"). Nuclear power has relatively higher capital cost, lower variable cost, and lower flexibility (ramping capability, minimum stable output, and cycling parameters) than the other firm low-carbon resources modeled. These techno-economic characteristics appear to make nuclear less well suited to pair with low-cost wind and solar, at least for the specific generation cost and performance assumptions herein (Tables SI-2 & SI-4). Across the full range of modeled technology design space parameters, the largest power system cost reduction due to LDES deployment is in the 45-50% range. When the parameter range is limited to the "future feasible regions" for known LDES technologies, the maximum cost reduction is in the 35-40% range. These future feasible regions are represented in the plots by the area to the right of the red lines, which correspond to the convex hull joining the highest efficiency/lowest weighted power cost performance regions for the LDES technologies summarized in Figure SI-1 and Table 2. Dot-dashed lines correspond to the convex hull of LDES resources that face geographic constraints on deployment (e.g., geological hydrogen or compressed air energy storage requiring specific geologic formations to realize estimated energy capacity costs), while solid lines represent the convex hull of geographically unconstrained LDES technologies. For the gas w/CCS and Blue $H_2$ cases, the maximum observed cost reduction declines to 30-35% across the whole modeled design space, to 20-25% within the future feasible regions for geographically-constrained LDES technologies, and 10-15% for unconstrained technologies.

In order to better understand the drivers of LDES value creation, we perform a regression analysis on the 7,680 data points included in Figures 1 and SI-3. For the regression analysis we preserve the original dimensionality of the LDES design space (5 dimensions, versus the 3 dimensions plotted in Figures 1 and SI-3) and include categorical variables for the scenarios for system and available firm low-carbon technology (Table 4). Table 1 shows a summary of the regression analysis on the data after a Min-Max Normalization of the non-categorical regressors ($\beta_1$ - $\beta_5$). The results confirm the rather modest impact of regional geography ($\beta_6$) on the LDES system value. Keeping everything else constant the cost reduction would be only 0.3% greater in the Northern System than the Southern System. The impact of varying the available firm low-carbon resource is larger ($\beta_7$ and $\beta_8$). With blue $H_2$ as reference, and keeping everything else constant, the average cost reduction (i.e., the increase in LDES system value) would be 1% greater if gas with CCS was the available firm resource and 9% if nuclear was available instead.

The regression results also corroborate the relative importance of LDES design space parameters observed in Figures 1 and SI-3 and provide further insights into the most important drivers of the system value of LDES. First, the energy capacity cost ($\beta_1$) is the regressor with the largest coefficient predicting system value of LDES (this coefficient is negative because the system value of LDES increases as the energy capacity cost declines). Figure SI-5 shows the yearly cycling of the least-utilized 1% of installed LDES energy storage capacity, which we refer to as the "marginal increment of capacity," versus the LDES system value and demonstrates that in cases with the greatest LDES system value, the marginal increment of energy storage capacity is cycled (charged/discharged) less than 10 times per year. Such infrequent utilization requires very low energy capacity costs to be economic.

Additionally, this regression analysis decomposes charge and discharge power costs and efficiencies and indicates that discharge efficiency ($\beta_4$) is the second most important factor in determining LDES system value after energy capacity cost, while charge efficiency ($\beta_5$) and charge and discharge power capacity cost ($\beta_2$ and $\beta_3$) are of secondary importance. Regression coefficients indicate that a given improvement in discharge efficiency has roughly twice the impact as an equivalent improvement in charge efficiency. This makes intuitive sense in that an improvement in discharge efficiency reduces both the energy storage capacity and the charge power capacity required to deliver a given amount of electricity output upon discharge. In other words, higher (lower) discharge efficiency requires lower (higher) charge power and energy storage capacity cost, all else equal.

Finally, improvements to discharge power capacity cost have slightly greater impact than equivalent improvements in charge power capacity cost ($\beta_2$ and $\beta_3$). Figure SI-6 compares the percentage of hours that are spent in charging versus discharging and shows that LDES systems generally spend a greater fraction of the year charging than discharging. This indicates that LDES technologies in decarbonized power systems are able to charge over longer periods of time when excess renewable energy is available and electricity prices are zero or near-zero, whereas these assets will be required to discharge energy during shorter periods of time due to VRE energy shortages, making improvements in discharge power capacity cost more valuable to the system than improvements in charge power capacity cost.

**Table 1.** Reduced Cost Multivariate Regression On Min-Max Normalized Descriptors

| Coefficients | Factor | Estimate | Std. Error | t value | Pr(>\|t\|)[2] |
|---|---|---|---|---|---|
| (Intercept) | $\alpha$ | 2.96 | 0.18 | 16.71 | <2e-16 *** |
| USD kWh | $\beta_1$ | -9.94 | 0.15 | -68.27 | <2e-16 *** |
| USD kW Discharge | $\beta_2$ | -3.26 | 0.14 | -23.63 | <2e-16 *** |
| USD kW Charge | $\beta_3$ | -2.89 | 0.14 | -20.95 | <2e-16 *** |
| Charge Eff. | $\beta_4$ | 3.21 | 0.14 | 22.90 | <2e-16 *** |
| Discharge Eff. | $\beta_5$ | 7.30 | 0.14 | 52.07 | <2e-16 *** |
| System: Northern[a] | $\beta_6$ | 0.31 | 0.11 | 2.97 | 0.00299 ** |
| Firm Tech: Gas w/CCS[b] | $\beta_7$ | 1.14 | 0.13 | 8.90 | <2e-16 *** |
| Firm Tech: Nuclear[b] | $\beta_8$ | 9.00 | 0.13 | 70.26 | <2e-16 *** |

**Model:** $\mathit{Cost\ Reduction}[\%] = \alpha + \beta_1 + \beta_2 + \beta_3 + \beta_4 + \beta_5 + \beta_6 + \beta_7 + \beta_8$

[1] observations: 7680

[2] Significance codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

[3] Residual standard error: 4.581 on 7671 degrees of freedom

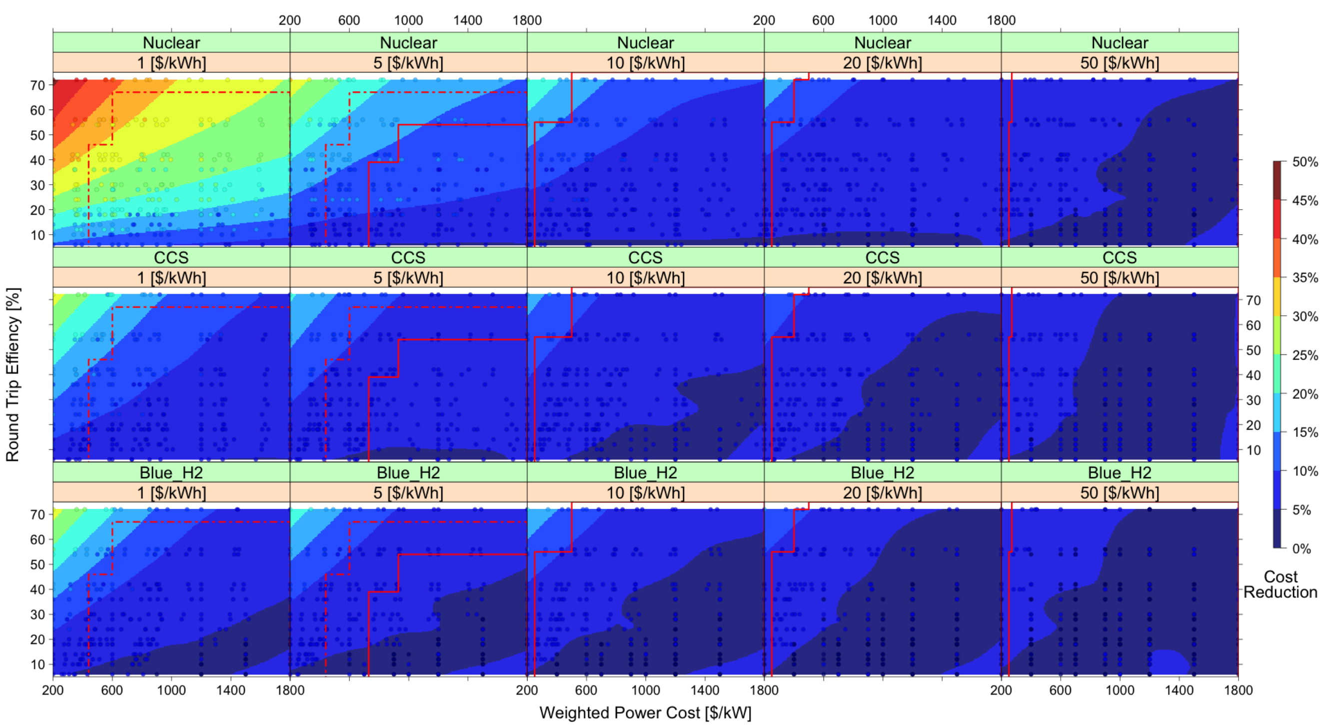
[4] Multiple R-squared: 0.6579, Adjusted R-squared: 0.6576

[5] F-statistic: 1844 on 8 and 7671 DF, p-value: < 2.2e-16

[a] Binary for categorical variable "System" {Northern,Southern}

[b] Binaries for categorical variable "Firm Tech" {Gas w/CCS,Nuclear,Blue $H_2$}

Figure 2 presents the system value of LDES in the Northern System under a scenario with high electrification of transportation, heating, and industrial energy supply, consistent with the goal of reducing economy-wide greenhouse gas emissions by 80% below 1990 levels by 2050[23]. The results indicate that further electrification of energy supply in Northern latitudes reduces the system value of LDES. The maximum system value in the future feasible regions for known LDES technologies remains at 35-40% under the high electrification scenario, but only in the most extreme upper-left corner of the feasible region for geographically-constrained resources and only when nuclear is the firm resource. For LDES resources without geographic constraints the maximum system value falls from 25-35% with current electricity demand profiles to a maximum of 15-20% with high demand electrification. Similarly, when CCS and Blue $H_2$ are available, the maximum system value of LDES in the feasible region for geographically-constrained LDES technologies falls from 25-30% to 15-20% under high electrification. LDES system value is limited to 10% in the feasible region for technologies without geographical constraints. In the high electrification scenario the peak demand in the Northern System increases from 36 GW to 77 GW, the median demand increases from 21 GW to 33 GW, the maximum hourly change in demand (ramp) increases from 3.4 GW to 17.4 GW, and the median ramp increases from 0.5 GW to 1.7 GW. As shown in Figure SI-47, electrification also adds a strong seasonal component to load variation due to electrification of heating. These changes in the demand profile increase the value of power capacity in the system relative to the value of energy shifting capacity, thereby increasing the competitiveness of firm low-carbon resources while reducing (but not eliminating) the relative system value of LDES.




Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in system costs. "Future feasible regions" for known LDES technologies from Figure SI-1 are plotted to the right of the dash-dotted lines (geographically constrained) and solid lines (unconstrained) for each row. Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total annualized system costs for the reference cases (in USD per MWh) are as follows: nuclear - $90.33; gas w/CCS - $66.93; Blue $H_2$ - $66.78.

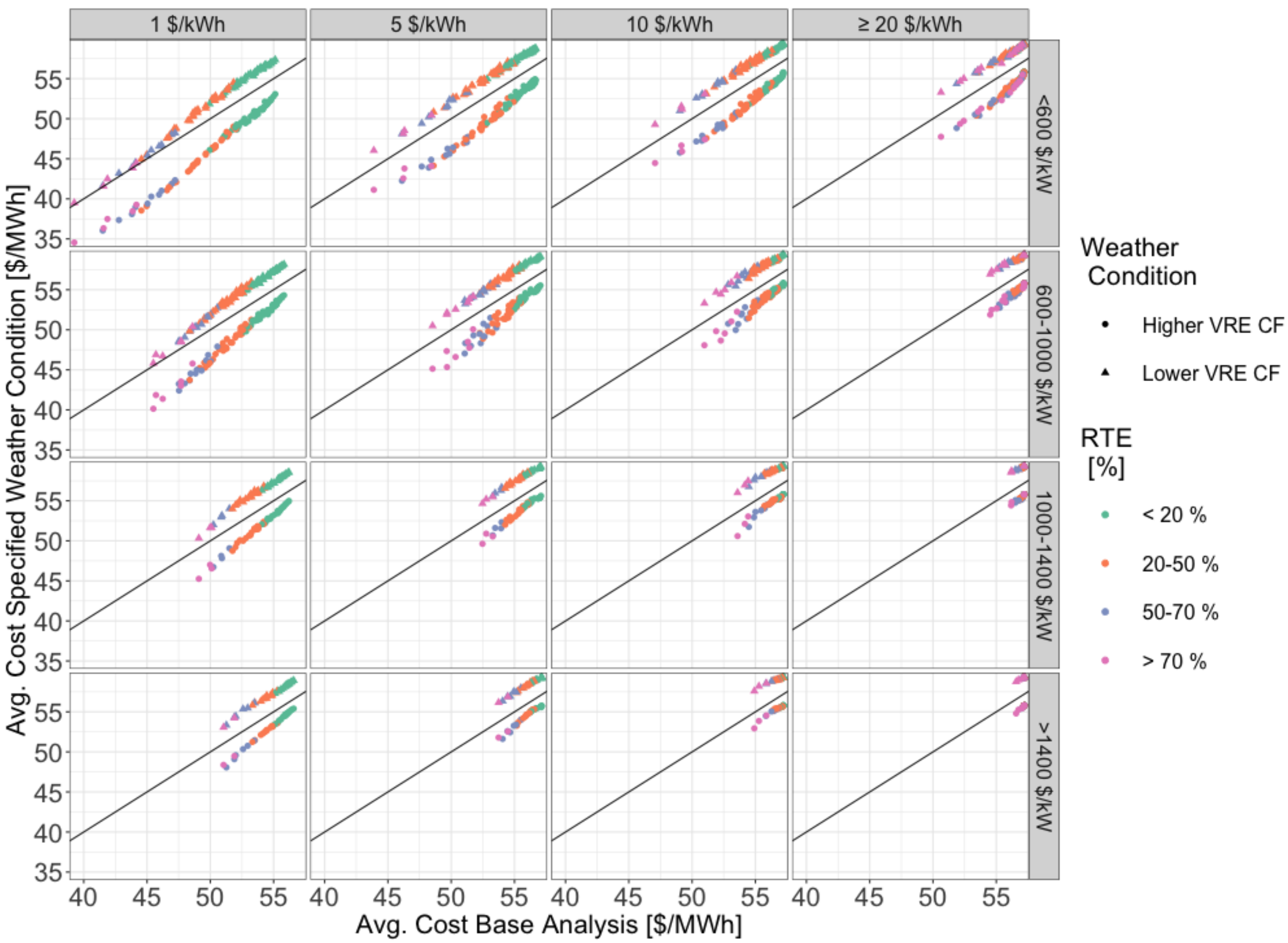
**Figure 2.** Northern System with Electrified Load: Percentage Reduction in System Cost for LDES Parameter Combination Compared to Reference Cases (Scenarios 7-9 in Table 4)

Future costs of wind, solar, and Li-ion batteries are predicted to continue declining, yet the exact pace remains uncertain. On the one hand, lower cost wind and solar favor increasing VRE penetrations and the accompanying volatility in net load, thereby increasing the market opportunity for storage technologies, Li-ion and LDES. On the other hand, lower cost wind, solar, or batteries reduce the relative capacity substitution value of LDES, which is shown to be central to the system value of storage technologies[24]. Which effect dominates outcomes is unclear *a priori*. As we use the low-range cost trajectory for these technologies from the National Renewable Energy Laboratory (Annual Technology Baseline 2018 (ATB 2018)[25] for Scenarios 1-10, we also run Scenarios 12-14, which replicate Scenarios 7-9 (Northern System, High Electrification) with the ATB 2018 mid-range cost trajectory for wind, solar and batteries (see Table SI-4. With higher VRE and battery costs, we find that the maximum system cost reduction from LDES declines from 50% (Figure 2) to 37% (Figure SI-4). The system value of LDES–in both relative (%) and absolute ($/MWh) terms–is lower across the entire design space. This finding indicates that LDES is most valuable in futures with low wind and solar costs, all else equal, while firm low-carbon resources retain importance in cases with more moderate wind, solar, and battery cost declines.

Figure 3 depicts the sensitivity of the average cost of delivered electricity due to changes in the weather data under more extreme weather years (see Methods) with availability of wind and solar resources (higher or lower VRE capacity factor) across the full range of LDES technology design space cases. Each data point on the plot corresponds to a specific set of LDES design space parameters, the x-axis value is the result obtained under base weather assumptions (Scenario 5 in Table 4), while the the y-axis value is the result obtained when changing the weather conditions (Scenarios 10 and 11 in Table 4). Note that capacity results are re-optimized in each case pointing to the effect that weather uncertainty would have on the spread of the distribution of results if capacity were optimized in a stochastic environment. The results show that in general, for the same combination of LDES parameters, the average cost of electricity is lower for the Higher VRE CF (Capacity Factor) Scenario and higher for the Lower VRE CF Scenario. This is expected, as higher/lower VRE availability should decrease/increase the levelized cost of electricity from wind and solar resources and have a corresponding effect on total electricity system cost. However, the figure demonstrates that for very low energy capacity cost LDES cases (i.e., $1/kWh), weighted power cost below $1000/kW, and RTE greater than 50% the average cost of electricity with lower VRE availability approaches the solid line (i.e., the result is the same as in the case using base weather assumptions), whereas the cost savings for the higher VRE case are greater. This suggests that LDES technologies with very low energy capacity costs can provide a hedge against the adverse impacts of years with unfavorable wind and solar conditions.

### Displacing Firm Generation and Lithium Ion Storage Capacity with LDES Technologies

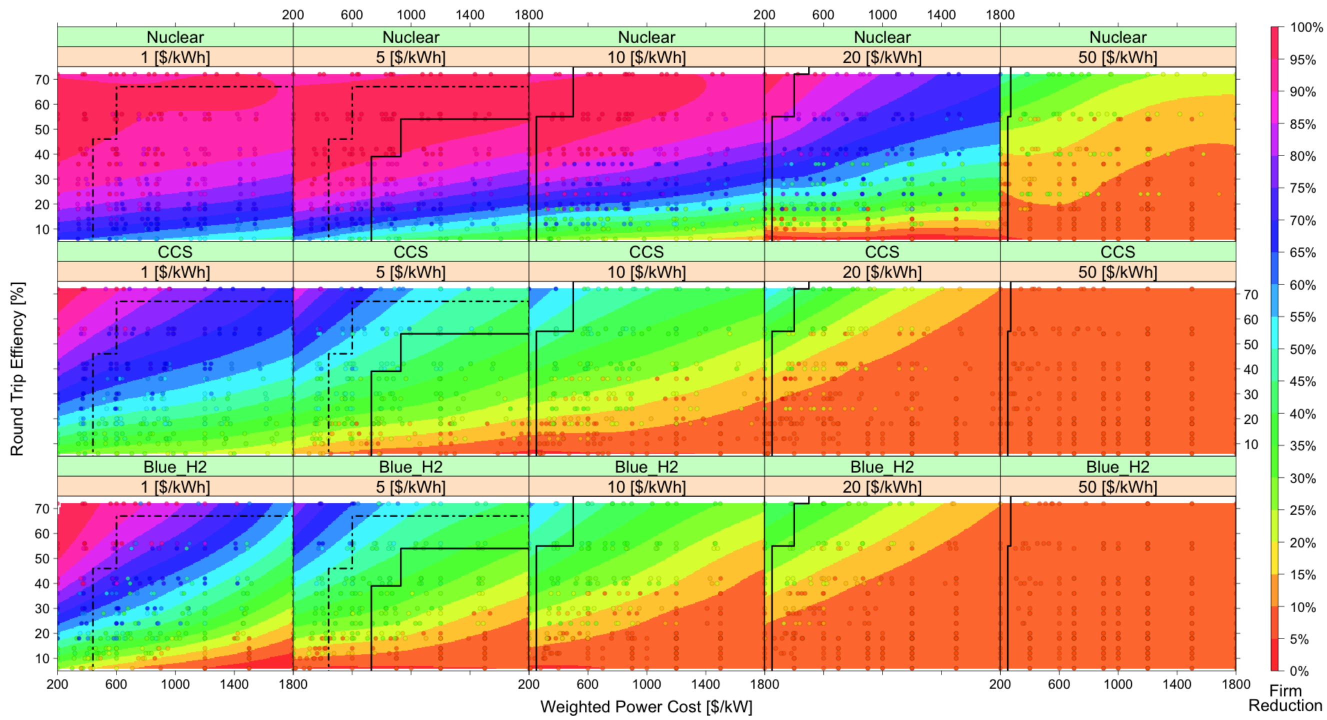
Figures 4 and SI-7 show the reductions in firm low-carbon capacity enabled by LDES for the Northern and Southern systems under current demand profiles relative to the corresponding cases without LDES. Figures SI-36 to SI-44 present results for firm capacity reduction in the original 5-dimensional space for energy capacity costs of $1-10/kWh. The reduction in firm capacity ranges from 0% (i.e., there is no change in firm capacity relative to the reference case) to a maximum of 100% (the firm capacity in the reference case has been completely displaced). In contrast to the previous results for the system value of LDES, there are significant differences between the Northern and Southern systems in this outcome metric. In general, the impact on firm capacity displacement is greater in the Southern system. As with system value, the results are sensitive to which




The figure shows the perturbation effect of VRE profile changes on average cost of electricity, the solid line marks the region of no perturbation (points in the line) in average cost of electricity cost as VRE availability changes. The space above the line corresponds to the region of increased average cost of electricity and the space below the line corresponds to the region of reduced average cost of electricity. Panels going left-right indicate different energy capacity cost levels and panels going bottom-up indicate different weighted power cost levels

**Figure 3.** Northern System: Effect on Average Cost of Electricity due to Changes in Weather (VRE Availability) Conditions

firm low-carbon technology is assumed to be available. When nuclear is the firm resource, the extent of substitution by LDES is generally greater than for gas w/CCS and Blue $H_2$. In both regions, complete displacement of gas w/CCS and Blue $H_2$ would require LDES technologies with energy capacity cost $\leq$\$1/kWh, power cost $\leq$\$400/kW, and round-trip efficiency $\geq$50%, a combination that appears to fall outside the feasible performance region for projected technologies.

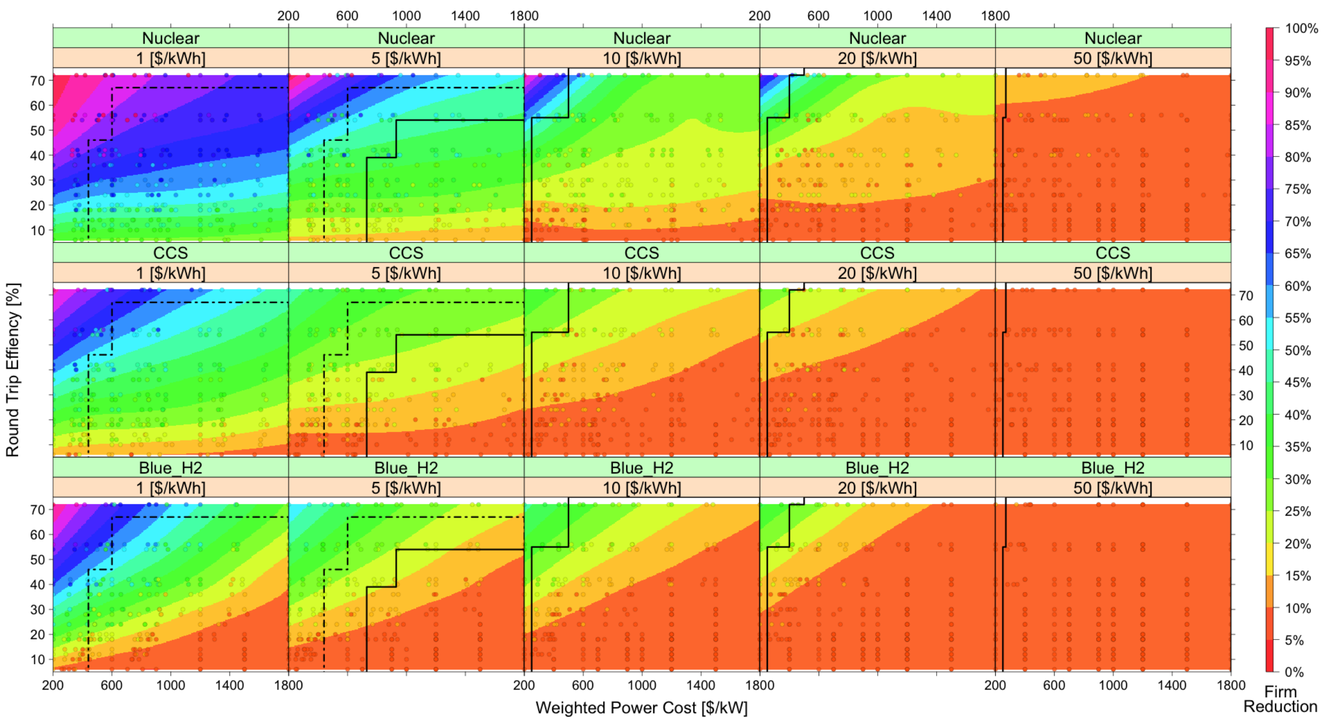



Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in firm capacity. "Future feasible regions" for known LDES technologies from Figure SI-1 are plotted to the right of the dash-dotted lines (geographically constrained) and solid lines (unconstrained) for each row. Each column represents a specific LDES energy capacity cost (\$/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total firm capacity for the reference cases normalized by peak demand (in %) are as follows: nuclear - 48.6%; gas w/CCS - 48.5%; Blue $H_2$ - 44.3%.

**Figure 4.** Northern System: Percentage Reduction in Firm Capacity for LDES Parameter Combination Compared to Reference Cases (Scenarios 4-6 in Table 4)

Figure 5 shows the percentage reduction in firm low-carbon capacity brought about by LDES deployment in the Northern system assuming high electrification (Scenarios 7-9). The results indicate that changes in the demand profile associated with high electrification drastically reduce the displacement of firm capacity by LDES, eliminating most of the 100% displacement regions seen in Figure 4. Together with cost results shown in Figure 2, these results indicate that electrification of energy supply in northern latitudes increases the value of firm capacity due to increased short-term variability and more pronounced seasonal variations in demand. While the displacement of firm low-carbon generation is diminished in high-electrification scenarios, LDES still retains the potential to reduce electricity cost in such scenarios, as Figure 2 shows.

Additionally, Figure SI-8 illustrates the impact of relatively higher wind, solar, and battery costs on firm substitution in the Northern System with high electrification (Scenarios 12-14). Across areas of low energy capacity cost (e.g. <5\$/kWh) and higher RTE (>50%), firm substitution further declines (relative to Scenarios 7-9) across all firm technologies, confirming the relatively lower system value of LDES if wind, solar, and storage costs decline at a more moderate rate in future years. However, across areas with higher energy storage capacity costs (10-50\$/kWh), changes in firm substitution are more complex: areas of 10-50% firm substitution expand for gas w/CCS and Blue $H_2$, but shrink for nuclear. Indeed, with nuclear, there are now areas of the design space where LDES increases nuclear capacity by up to 10%. The likely cause of these seemingly contradictory effects is actually the same: in this region of the design space, LDES is deployed with shorter duration (<50 hours, Figure SI-23) and competes primarily with Li-ion batteries. As Li-ion is more costly in Scenarios 12-14 relative to Scenarios 7-9, LDES achieves greater substitution of Li-ion (Figures SI-15 and SI-16). With LDES now relatively cheaper than Li-ion in this shorter-duration role, the greater deployment of LDES reduces both peaks and valleys in the net load that must be served by firm resources. Gas w/CCS or Blue $H_2$ capacity that is used to meet infrequent peaks in net load can thus be avoided, while valleys in net load are also reduced, increasing the capacity factor and relative value of nuclear. These differing substitution effects for nuclear vs. gas w/CCS and Blue $H_2$ stem from the ratio of fixed to variable costs (higher for nuclear, lower for the two fuel combustion technologies).




Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in firm capacity. “Future feasible regions” for known LDES technologies from Figure SI-1 are plotted to the right of the dash-dotted lines (geographically constrained) and solid lines (unconstrained) for each row. Each column represents a specific LDES energy capacity cost (\$/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total firm capacity for the reference cases normalized by peak demand (in %) are as follows: nuclear - 48.6%; gas w/CCS - 51.3%; Blue $H_2$ - 47.5%.

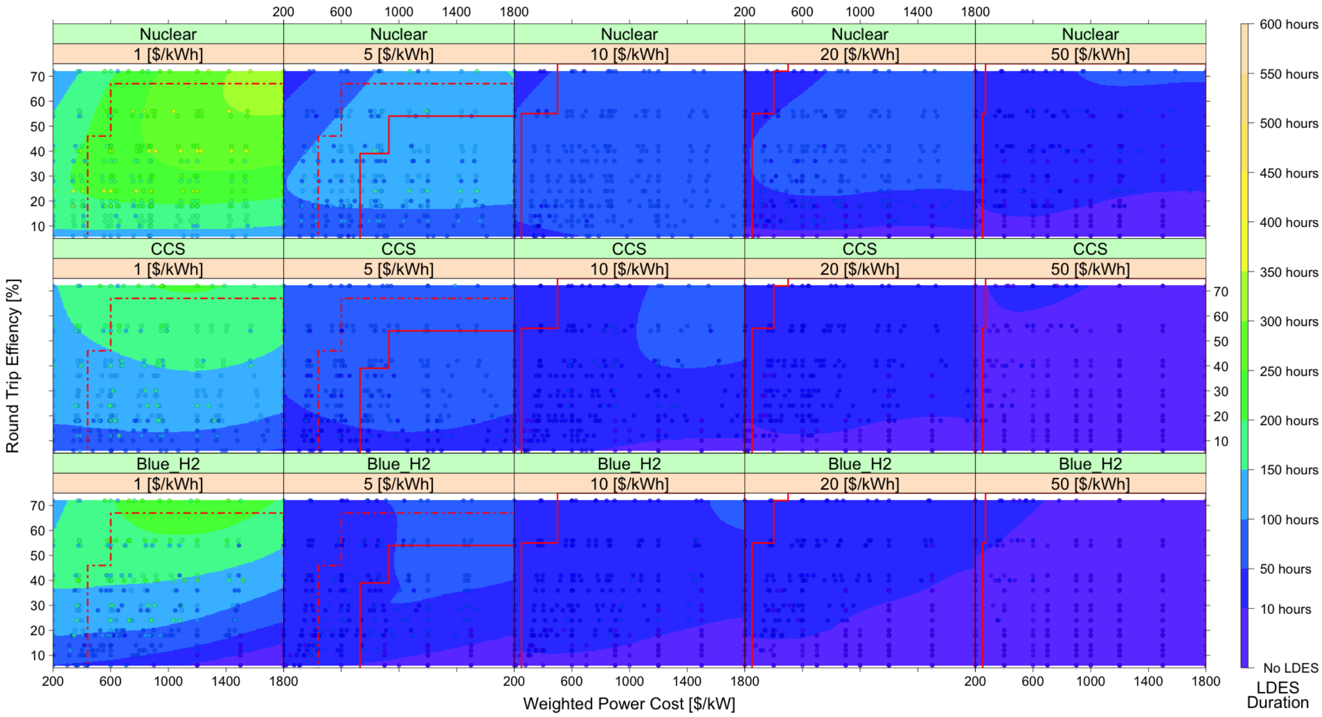
**Figure 5.** Northern System with Electrified Load: Percentage Reduction in Firm Capacity for LDES Parameter Combination Compared to Reference Cases (Scenarios 7-9 in Table 4)

Figures SI-9 through SI-16 show the impact on Li-ion power and energy capacity of introducing LDES to the capacity expansion framework. These results demonstrate that LDES does not significantly displace Li-ion capacity until LDES weighted power cost falls ≤\$800/kW at ≥70% RTE. There are also areas of the LDES design space where Li-ion power and energy capacity are higher than the case with no LDES. These findings indicate that unless LDES technologies exhibit a sufficient combination of low power costs and relatively high efficiency, they are weak substitutes or even complements for Li-ion batteries. This confirms the finding in Sepulveda et al.[1] that Li-ion batteries play a very different role in low-carbon power systems as "fast burst balancing resources" that primarily provide power and flexibility services over shorter durations (typically a few hours). By contrast, LDES technologies, which provide sustained energy supply over long periods, have the potential to substitute directly for firm generation, particularly if low energy capacity costs are achieved. Figure SI-24 reinforces this finding by highlighting the different operating patterns of LDES and Li-ion across a range of LDES power capacity and energy capacity costs for the Northern system with gas/CCS (Scenario 5). As LDES energy capacity cost is reduced from \$10 to \$1/kWh, firm displacement increases and is accompanied by a shift in LDES operations from multiple near-complete charge-discharge cycles to a single such cycle spanning seasons. If LDES simultaneously achieves both low energy capacity cost and low power cost/high RTE, then LDES could substitute for both firm generation and Li-ion or other short-duration "fast burst" storage technologies. In such a case, Figure SI-24 indicates that LDES operations will exhibit increased high power, low energy (e.g. intra-day) cycling to compensate for the role played by Li-ion without impacting high energy cycles occurring over longer periods. However, the LDES performance requirements to fully displace Li-ion and also displace a large amount of firm resources mostly lie beyond the future feasible regions for known LDES technologies.

## Design of LDES Technologies

In this study, we set the minimum energy capacity to discharge power ratio for LDES systems at 10:1 and the maximum at 1000:1 (Li-ion storage is modeled as ≤10:1 energy to power ratio). The capacity expansion model then optimizes energy capacity and discharge capacity independently within this range. Note that energy to power ratio is often described as the storage duration. However, the maximum duration of sustained discharge that any storage technology can achieve is also affected by the discharge efficiency, which is important given that some LDES technologies have relatively low discharge efficiencies. We therefore define LDES 'duration' (in hours) as $(E \cdot \eta^{-})/P_d$, and refer to the ratio of $E/P_d$ as the LDES 'energy to power ratio,' where $E$, $P_d$, and $\eta^{-}$ are the energy capacity, discharge power capacity, and discharge efficiency, respectively.

Figures SI-17 and SI-18 present results for the LDES energy to power ratio in the system for the Northern and Southern systems respectively, and Figures 6 and SI-21 present the LDES duration. These figures show that for energy capacity costs of ≥\$10/kWh, LDES duration is generally in the 100 hour range (with energy-to-power ratios reaching as high as 300 hours when efficiency is low). This also holds for energy capacity costs of \$5/kWh if gas w/CCS or Blue $H_2$ are the available firm generation options. Additionally, duration is largely unaffected by weighted power capacity cost at these levels but somewhat more affected by round-trip efficiency. In general, higher energy-to-power ratio and discharge durations occur in both the Northern and Southern systems when nuclear is the available firm low-carbon technology. With very low energy capacity costs of \$1/kWh, we see durations reaching the 400 hour range, with energy-to-power ratios as high as 900:1. These findings suggest that the maximum sustained discharge period required for LDES capacity generally ranges from several days to a few weeks, rather than months or seasonally. However, LDES may charge over longer time periods (see Figure SI-6), and the utilization of energy capacity may exhibit seasonal patterns (see Figure SI-24).




Each row of plots represents a different scenario using a different firm low-carbon technology. "Future feasible regions" for known LDES technologies from Figure SI-1 are plotted to the right of the dash-dotted lines (geographically constrained) and solid lines (unconstrained) for each row. Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency.

**Figure 6.** Northern System: LDES duration (Energy Capacity x Discharge Efficiency)/(Discharge Capacity) in hours for optimal deployment of LDES

Figure SI-19 and Figure SI-22 show LDES energy-to-power ratio and discharge duration results for the Northern System under electrified energy assumptions. Duration increases with electrification of energy demand, especially for cases when nuclear power is the firm low-carbon resource, reaching values in the 650 hour range for an energy capacity cost of $1/kWh. Note that the imposed maximum energy-to-power ratio of 1000:1 is binding in 60 cases with electrified energy assumptions in the Northern System with very low discharge efficiencies ($\leq$ 36% RTE) and an energy capacity cost of $1/kWh (see Figure SI-19).

While most electrochemical storage technologies use the same cathode/anode system for charging and discharging and thus have symmetric power capacity and efficiency parameters, most chemical and thermal storage technologies and some mechanical storage technologies use distinct mechanisms or devices for charging and discharging. We can thus further explore the relationship between the discharge power capacity and the charge power capacity to see whether LDES systems typically employ balanced or asymmetric power capacity when these decisions are independently optimized. Figures SI-25 and SI-26 show 2D histograms of the resulting discharge power capacity and the charge power capacity, both normalized by the peak demand in the system. The figures show that optimized LDES power capacities are frequently unbalanced. In both the Northern and Southern systems, we can see areas of greater density that extend from the diagonal line (where systems are perfectly balanced) into the lower diagonal sub-space (the region of increased discharge power capacity compared to charge power capacity) for cases with deployed discharge power capacity up to 30% of peak demand. This trend shows a generally greater need for discharge power capacity in the LDES systems. This is attributable to the fact that LDES systems are able to charge over longer periods of time, but must inject energy back into the system more rapidly when VRE resources are not available (Figure SI-6). Nevertheless, a small number of cases exhibit unbalanced systems in the other direction, with a preference for greater charge capacity. Specifically, these occur for combinations of very low energy capacity cost and very low charge power capacity cost. The optimal configuration of LDES power capacities thus depends on where a technology ultimately falls within the LDES design space.

## Discussion

In power systems with high variable renewable energy shares, sufficient capacity is required from reliable electricity sources that can sustain output in any season and for long periods, including periods of several days or weeks when average demand exceeds average wind and solar supply. These periods are sometimes referred to as *Dunkelflaute*, a German compound word translating approximately to 'dark doldrums', and they typically occur during persistent weather patterns spanning large areas. Prior work has demonstrated that one or more of several candidate firm low-carbon generation technologies (nuclear, natural gas w/carbon capture and sequestration (CCS), geothermal, bioenergy, or other zero-carbon fuels such as hydrogen) can displace fossil-fueled firm generation sources and complement variable renewable energy generation to cost-effectively meet reliability needs in deeply decarbonized power systems. Other studies suggest replacing firm low-carbon generation with one or more energy storage media capable of sustained output over weeks or longer and suited to low annual utilization rates. No such energy storage options have yet been commercially deployed at large scale. Several technologies have the potential to become technically and economically suited to this task, but their eventual cost and performance remains uncertain.

In this paper, we evaluate a wide range of combinations of potential cost (for charge, discharge, and energy capacity) and engineering performance (charge and discharge efficiency) for long duration energy storage (LDES) technologies, which we call "the LDES technology design space." This evaluation of the LDES design space provides insights into the most important directions for innovation in LDES technologies. It helps identify cost and performance outcomes necessary for LDES to substitute, in part or in full, for firm low-carbon generation and for LDES to meaningfully reduce the cost of decarbonized power systems.

We find that "meaningful" displacement of firm low-carbon resources – i.e., reductions in firm low-carbon capacity by more than 10% compared with the reference cases – begins to occur at storage energy capacity cost levels of $50/kWh. This initial displacement of firm resources by LDES has little to no impact on total electricity costs, however, and can be viewed as the initial cost-competitiveness threshold for LDES in the system. Because the system value of LDES declines with increasing penetration, our analysis finds that LDES energy capacity cost must fall below $20/kWh for LDES technologies to "meaningfully" reduce total electricity costs in a decarbonized power system – i.e., to achieve an overall cost reduction of 10% or more compared with the reference cases. This finding is consistent with target range of energy capacity costs identified by ARPA-E's DAYS program[10] for LDES technologies with duration at rated power greater than 50 hours.

Within the entire LDES design space explored in this work, we found that up a 45-50% cost reduction from the reference cases could in principle be achieved when LDES combines very low energy capacity cost ($1/kWh), low power capacity cost ($100/kW) and high round-trip efficiency (72%). However, we found a maximum reduction between 35-40% when considering combinations of cost and efficiency performance that fall within the "future feasible regions" based on projections for known LDES technologies now under development. Moreover, the ability of LDES to lower electricity costs is reduced when greater electrification of heating, transportation, and industrial energy demand is assumed.

Additionally, our results show that full displacement of firm low-carbon resources could potentially be achieved at energy capacity cost of $\leq$\$10/kWh if nuclear is the only firm low-carbon technology that is available. Energy capacity cost must fall to $\sim$\$1/kWh in combination with very low weighted power cost ($\sim$\$200/kW) and relatively high round-trip efficiencies ($>$60%) to eliminate all firm low-carbon options (gas w/CCS and Blue $H_2$) from the power system. Within the "future feasible regions" of the LDES design space, full substitution of firm generation only occurs when nuclear is the only available firm resource and under historical electricity demand profiles. Fully displacing firm generation in a high electrification scenario in a northern-latitude power system requires combinations of cost and efficiency performance that fall outside the future feasible performance region for known LDES technologies (e.g. energy capacity cost of $\sim$\$1/kWh, weighted power cost $\leq$\$400/kW, and round-trip efficiency of 50% or greater).

We note that the LDES design parameters required to fully displace firm generation identified in this work differ from recent findings of Ziegler et al.[13]. That study concludes that LDES could deliver "baseload" or constant output from wind or solar facilities at a lower average cost of generation than firm low-carbon resources (e.g. new nuclear power plants) with energy capacity costs below $20/kWh, a symmetrical charge/discharge power cost of $1000/kW (equivalent to a weighted power cost of $1000/kW) and a round-trip efficiency of 75%. Their analysis takes a plant-level perspective, finding the minimum cost combination of wind/solar and LDES capacity to deliver fixed power output shapes from an individual facility. In contrast, our analysis captures system-level interactions of all electricity resources, accounts for realistic demand and LDES operation profiles, and captures declining marginal value of LDES and other resources endogenously at the system level. Thus, the system value and cost-competitiveness of LDES in our study is affected dynamically as deployment of LDES increases and is impacted by the characteristics of other resources in the system, including which firm low-carbon generation technology is available. Accounting for these system-level effects, we find that energy capacity cost levels of $20/kWh, a weighted power cost of $1000/kW, and a round-trip efficiency of 72% (the highest level modeled here) result in a maximum reduction in firm low-carbon generation capacity of $\sim$60% and total electricity cost savings of 15-20% when competing against nuclear and when modeling historical demand profiles. Firm capacity substitution falls to <40% and cost savings are <10% when gas w/CCS or Blue $H_2$ are available as well as under high end-use electrification in the northern system (regardless of the firm resource).

The differences in findings between these two studies illustrates the importance of analytical frameworks that endogenously capture competition and complementarity between various electricity resources when evaluating cost and performance objectives for novel low-carbon electricity technologies. Our approach allows LDES systems to be deployed and sized to maximize system value/reduce total electricity cost while accounting for system-level synergies and competing effects between technologies. This framework allows us to independently evaluate the effects that changes in one specific cost/performance parameter or competing technology can potentially have on the overall system value of LDES and the extent of LDES capacity deployment. Our research explored thousands of cases and combinations of LDES parameters and provides several insights that can help inform developers and designers of LDES technologies.

First, we find that energy capacity cost is the greatest driver of LDES system value (i.e., reductions in total power system cost), followed by the discharge efficiency. This suggests that research and development efforts should concentrate on LDES technologies that are capable of achieving very low cost per kWh for energy capacity, with the greatest LDES system value generally exhibited for costs in the \$1-10/kWh range and discharge efficiencies greater than 60%.

Second, we find that the characteristics of competing firm low-carbon technologies are second only to energy capacity cost in the impact on LDES deployment rates and system effects. This finding also reinforces the relevance of endogenous competition for technology valuation to capture synergies and competing effects that can affect LDES's marginal value to the system. LDES cannot be evaluated in vacuum. We find that the system value of LDES is greatly enhanced when competing against nuclear at the specific costs and engineering constraints modeled herein. (One could expect similar results for geothermal power plants with similar characteristics.) LDES system value is substantially lower when firm low-carbon resources with lower capital costs, higher fuel costs, and greater operating flexibility are available – e.g. natural gas plants with CCS or combustion plants burning hydrogen or another zero carbon fuel (ammonia, biomethane, synthetic methane). It is also important to note that in deeply decarbonized future power systems, LDES will likely compete against not just one alternative firm low-carbon technology but several at the same time. Therefore, our results likely present upper bounds to the value that LDES could provide in such systems, as expanding the set of available firm low-carbon resources would accelerate the decline in the marginal value of all resources in the system, including LDES.

Third, in agreement with Albertus et al.[11], we find that the storage duration of LDES systems should be greater than 100 hours to maximize LDES system value and reductions in total electricity costs. In our results, LDES duration concentrates in the 100-400 hour range (or up to 16 days), although the duration increases to as much as 650 hours or >27 days when considering high electrification demand profiles and very low energy capacity costs. Our findings also indicate that the focus of ARPA-E's DAYS program[10] on storage resources capable of 10-100 hours duration is likely to be too limited to achieve the greatest potential system value for LDES technologies.

Fourth, we find that the system value of LDES is maximized when charge and discharge capacities are unbalanced or asymmetrical, with a general observed preference for higher discharge power capacity over charge power capacity. This indicates that technologies that are able to decouple these two capacity components – including many chemical, thermal, and mechanical technologies – might be more competitive, all else equal. However, our results also demonstrate that power capacity costs have a much more limited effect on LDES system value than energy capacity cost and discharge efficiency. We also see only a small difference in the relative importance of discharge power capacity cost versus charge power capacity cost (see e.g. Table 1). For these reasons we conclude that technologies that cannot decouple the two power components (e.g., most electrochemical storage technologies) may not be substantially disadvantaged, provided they achieve sufficiently low energy capacity cost and competitive levels of performance in other dimensions.

To meet the cost targets estimated in this research, storage technologies will need to achieve ultra-low energy capacity costs. Mechanical energy storage technologies, such as pumped hydro storage (PHS) and compressed air energy storage (CAES), tend to have low energy capacity costs where suitable topography or underground caverns are available (e.g. very large reservoirs or caverns). PHS has been proven to work for large-scale installations over many decades, although most projects are built for diurnal cycling (6-24 hours duration) with costs in the \$100s per kWh range[26,27], and thus cannot serve as an LDES technology. Some PHS projects with very large reservoirs may have durations over 100 hours and costs in the \$20-30/kWh range[27,28]. Similarly, compressed air energy storage in very large saline aquifers could potentially result in costs as low as ∼\$1/kWh with 100s of hours duration, while more conventional projects in salt caverns have higher costs and shorter durations[29]. Importantly, both technologies have geographical constraints due to the uneven availability of the required aboveground or underground features, which may constrain further deployment. Moreover, while mechanical storage is scalable to large sizes, its energy density is considerably lower than electrochemical storage, and thus above-ground systems (e.g. PHS reservoirs) have large spatial footprints.

Electrochemical energy storage technologies face different limitations, including generally higher energy capacity costs compared to PHS and CAES. Flow batteries are an electrochemical technology platform that could potentially achieve lower energy capacity cost and can decouple power and energy capacity scaling decisions. Energy capacity costs for the most widely studied variants, vanadium redox and zinc bromine flow batteries, have been estimated in the \$100s per kWh range[13], too high to serve as a cost-effective LDES technology, according to our findings. Alternative flow batteries using very low cost materials[14] or aqueous metal-air batteries[15] may achieve lower energy capacity costs. For example, Li et al.[14] estimate materials costs for an air-breathing aqueous sulfur flow battery at \$1/kWh and installed energy capacity costs in the range of \$10-20/kWh at 100+ hour duration with a power capacity cost of ∼\$1000/kW. According to our results, these costs would fall within the aforementioned target ranges for initial cost-competitiveness and "meaningful" reductions in total electricity costs above a 10% threshold, but they would not be sufficient to fully displace firm low-carbon resources under most conditions.

Chemical energy storage candidates such as hydrogen, synthetic methane (SNG), and ammonia have the potential to achieve very low energy capital cost and uniquely exploit additional revenue streams due to the value of the underlying storage medium in other end-use sectors[30,31]. Similar to CAES, low energy capacity costs for chemical energy storage heavily depends on the use of specific geologic features, including man-made salt caverns, hard rock caverns, or deep porous formations. Cost estimates range from ∼\$0.5/kWh for naturally occurring porous rock formations such as depleted gas or oil fields or saline basins to

~\$0.8/kWh for large, solution mined salt caverns and ~\$1-5/kWh for lined hard rock caverns[32]. Compressed hydrogen storage in steel tanks may cost on the order of \$10-15/kWh[33,34]. Despite low energy capacity costs, chemical storage options have relatively low round-trip efficiencies (RTE), particularly discharge efficiency. Electrolysis (for "charging") achieves efficiencies of 51-77% while the efficiency of power production via combustion turbines, combined cycle power plants or fuel cells ranges from ~35-60% (for a RTE of ~18-46%)[20,35,36]. Hydrogen can be converted into SNG by reacting $H_2$ with carbon dioxide ($CO_2$), captured from air, in a second reaction step to produce methane ($CH_4$). The main benefits of SNG are that this gas allows energy to be stored in, and transported through, the extensive existing natural gas system as well as the higher volumetric energy density of $CH_4$ (vs $H_2$), bringing the above-ground cost of storage to ~\$5/kWh[37]. The inclusion of the methanation sub-process and $CO_2$ capture process further reduces the RTE and increases the power cost for the overall power to methane to power system[36]. Chemical storage systems also present relatively high power capacity cost due to the infrastructure required for the chemical processes and the cost of combustion power plants or fuel cells to convert stored chemical energy back to electricity. The lowest charge and discharge power costs reported in Table 2 for chemical storage pathways depend on substantial future cost reductions for both electrolysis and fuel cells to ~\$220/kW for each component[20,38].

Finally, the majority of thermal energy storage (TES) systems used for electricity applications today are found at concentrating solar power (CSP) plants using molten salt for storage. Molten salt storage energy capacity costs range from roughly \$30-80/kWh[39] and they rely on steam turbines to generate electricity with a cost of roughly \$600-700/kW for this power component alone and a relatively low discharge efficiency of under 40%. Resistive heating or integration with a concentrated thermal power plant or other high-temperature thermal source adds additional charging power costs to this system. This combination of costs puts conventional molten salt thermal storage outside of a competitive LDES design space. A variety of other thermal storage systems may offer greater potential as LDES technologies, but remain more speculative/less mature today than molten salt. In a recent study, Amy et al.[18] propose future estimates for a thermal energy grid storage system using multi-junction photovoltaics. Projected power capacity costs for this system range from \$250-350/kW, energy capacity costs range from \$8-36/kWh, with 40-55% round-trip efficiency for an electricity-to-heat-to-electricity system using two junction photovoltaics. Smallbone et al.[40] describe a reciprocating heat pump energy storage system with an estimated \$400-900/kW combined charge/discharge power cost, ~\$15-25/kWh energy storage capacity cost, and ~52-72% round-trip efficiency. Stack et al.[19] propose firebrick resistance-heated energy storage (FIRES) storing sensible heat at 1000-1500°C in ceramic 'firebricks' for industrial heat or electricity storage applications. FIRES could achieve an estimated \$50/kW charge power cost at ~98% charge efficiency and \$5-10/kWh energy storage capacity cost with temperatures suitable for use with a Brayton cycle for power generation at ~\$700-1100/kW and ~35-40% efficiency for discharge power or a combined cycle at ~\$900-1100/kW and ~50-55% efficiency (for a RTE of ~34-54%).

In summary, a variety of potential LDES technologies exist employing a wide range of mechanical, chemical, electrochemical, and thermal storage systems. Each offer different combinations of potential cost and performance parameters that fall within the wide design space assessed in this paper. This work thus offers a thorough evaluation of a diverse range of potential

LDES technologies and provides insight into their potential value in decarbonized electricity systems.

Finally, we note several limitations of this work. First, several LDES storage technologies with different combinations of cost and performance parameters may co-exist in future power systems. Having identified the subset of the broad LDES design space that is likely to produce economically attractive LDES technologies, this paper paves the way for future work that could include a discrete subset of these technologies with differing parameters and evaluate how multiple LDES technologies might compete with or complement one another. Second, we do not consider the impact of transmission constraints on the value and market adoption of LDES. By storing energy during periods of network congestion and delivering it when networks are unconstrained, LDES may act as a (partial) substitute transmission network upgrades, which may present a niche or early market opportunity for these technologies. Additionally, where transmission network expansion is significantly constrained by siting, permitting, and cost-allocation challenges, LDES may be a long-term and important alternative to integrate larger amounts of renewable energy[41]. A thorough evaluation of the specific technical and economic characteristics necessary for LDES to act as an effective substitute to transmission (or distribution) network upgrades remains a topic for future research. Third, we evaluate only techno-economic related considerations in this optimization framework. All resources considered herein–including the wide range of LDES technologies covered by the design space considered herein–have environmental and societal impacts or entail risks or hazards that may constrain their development, differentiate them on non-cost related dimensions, and ultimately impact their deployment. Promising LDES technologies should be further evaluated along a variety of non-cost related dimensions, including their own relative risks or impacts as well as their potential to change the aggregate portfolio of electricity resources and mitigate or exacerbate associated non-cost related impacts.

## Methods

In this study, we evaluate the role and value of LDES in deep decarbonization of power systems by exploring a wide range of possible design parameters for LDES technologies. We first construct a LDES "technology design space" starting from the target cost values that ARPA-E has specified as part of the DAYS program[10], with power capacity costs below \$1,000/kW and energy capacity costs below \$200/kWh, with a focus on the \$5-20/kWh range. We intersect these cost targets with findings from other researchers[11,13,14,42] suggesting that LDES energy capacity costs need to be below \$50/kWh, with some chemicals having the potential to reach \$1/kWh, and a power capacity cost target between \$500-1,000/kW. Finally, we incorporate parameters from our own literature review of academic peer-reviewed studies on current and future cost and performance objectives for LDES technologies summarized in Table 2.

Table 3 summarizes the full LDES technology design space explored in this research, with combinations of different values for charge power capacity cost, discharge power capacity cost, and energy capacity cost, together with values for charge and discharge efficiencies. Given uncertainty in future technology development, we evaluate a LDES design space that both encompasses performance levels that are consistent with projections of "future feasible regions" identified in the literature for existing or emerging LDES technologies (Table 2 and Figure SI-1) and also includes domains of performance lying outside

**Table 2.** Future Costs Projections for Long Duration Energy Storage Technologies

| Storage Method | Technology | Discharge Power Cost [c] ($/kW) | Charge Power Cost ($/kW) | Weighted Power Cost ($/kW) | Energy Capacity Cost [d] ($/kWh) | Charge Efficiency (%) | Discharge Efficiency (%) | Round-trip Efficiency (%) |
|---|---|---|---|---|---|---|---|---|
| Mechanical | Pumped Hydro Storage (PHS)[26,27] | 600-2000 | - | 600-2000 | 20+ [b] | - | - | 70-85% |
| | Compressed Air Energy Storage (CAES)[20,27,29] | 600-1150 | - | 600-1150 | 1-30+ [b] | - | - | 42-67% |
| Chemical | Power-H2-Power (Brayton Cycle)[6,35,36,43] | 700-1100 | 220-1400 | 920-2500 | 1-15+[a] | 51-77% | 35-40% | 18-31% |
| | Power-H2-Power (Combined Cycle)[6,35,36,43] | 900-1100 | 220-1400 | 1120-2500 | 1-15+[a] | 51-77% | 50-55% | 26-42% |
| | Power-H2-Power (Fuel Cell)[6,20,35,36,43] | 220-2000 | 220-1400 | 440-3400 | 1-15+[a] | 51-77% | 40-60% | 20-46% |
| | Power-SynGas-Power (Brayton Cycle)[6,35,36,43] | 700-1100 | 600-1700 | 1300-2800 | 1-5+[a] | 49-65% | 35-40% | 17-26% |
| | Power-SynGas-Power (Combined Cycle)[6,35,36,43] | 900-1100 | 600-1700 | 1500-2800 | 1-5+[a] | 49-65% | 50-55% | 25-36% |
| | Power-SynGas-Power (Fuel Cell)[6,20,35,36,43] | 220-2000 | 600-1700 | 820-3700 | 1-5+[a] | 49-65% | 40-60% | 20-39% |
| Electro-chemical | Aqueous Sulfur Flow Batteries[14] | 500-2000 | - | 500-2000 | 10-20 | - | - | 60-75% |
| | Vanadium Redox Flow Batteries[14] | 270-600 | - | 270-600 | 40-200 | - | - | 65-80% |
| Thermal | Multi-Junction PV Thermal Storage[18] | 250-350 | - | 250-350 | 8-36 | - | - | 40-55% |
| | Reciprocating Heat Pump Energy Storage[40] | 400-900 | - | 400-900 | 15-25 | - | - | 52-72% |
| | Firebrick Resistance-Heated (Brayton Cycle)[6,19,43] | 700-1100 | 30-50 | 730-1150 | 5-10 | 98% | 35-40% | 34-39% |
| | Firebrick Resistance-Heated (Combined Cycle)[6,19,43] | 900-1100 | 30-50 | 930-1150 | 5-10 | 98% | 50-55% | 49-54% |

[a] Lower end of the cost range subject to geological and geographic constraints
[b] Full cost range subject to geological and geographic constraints
[c] The quoted value for some technologies include the cost of the charging component as well (e.g. PHS)
[d] Energy capital cost is denoted in units of storage medium and not kWh of electricity.

these regions as a basis for exploring potential targets for future development efforts. A total of **1,280** combinations of these parameters were tested under different power system scenario configurations.

The capital cost parameters described in Table 3 correspond to the capital investment cost for each scaling dimension (discharge and charge power capacity and energy storage capacity) for LDES systems. These capital costs are on a fully installed basis inclusive of installation labor and construction financing. Capital cost are transformed into annuitized investment cost using a 30-year capital recovery period and a weighted average cost of capital of 7.1% (nominal). We provide a conversion table Table SI-5, which can be used to compare a resource with a different asset life or a different cost of capital assumption to the findings in this paper. The charge power capacity and energy storage capacity investments are assumed to have no O&M costs associated with them. A comparable fixed O&M cost from Li-ion batteries is assumed to be associated with the discharge power capacity investments of LDES. Self-discharge losses and system degradation for LDES systems and Li-ion batteries were not modeled in this work.

Additionally, we set the minimum ratio of rated energy capacity to rated discharge power capacity for the LDES technologies to be at least 10:1[10]. Li-ion batteries are deployable with energy to power ratios between 0.5:1 and 10:1 and with energy and power capacity sized independently – i.e., we assume a constant energy capacity scaling cost for Li-ion batteries with duration between $\sim$30 minutes and $\sim$10 hours. Although the ARPA-E program is focused on durations of up to a 100 hours, others have argued that longer durations will be required[11]. We set a maximum energy-to-power ratio of 1,000:1 to test this hypothesis and explore the effect of longer durations. Note that this 1,000:1 ratio constraint ends up non-binding in all but 60 cases modeled herein, all of which have RTE of 36% or lower and energy capacity cost of \$1/kWh. As mentioned previously the "LDES design space" includes a variety of technologies, with some technologies allowing energy and power capacity to be scaled independently, and some also allowing charge and discharge power capacity to be scaled independently. Our exploration of the LDES design space assumes that the three scaling dimensions – energy capacity, discharge power capacity, and charge power capacity – can be varied independently, even though all three degrees of freedom are not possible for certain technologies.

**Table 3.** LDES Design Space

| Design Characteristic | Values Explored |
|---|---|
| Charge Power Capacity Cost [$/kW] | 100,300,600,900 |
| Discharge Power Capacity Cost [$/kW] | 100,300,600,900 |
| Energy Capacity Cost [$/kWh] | 1,5,10,20,50 |
| Charge Efficiency [%] | 30,50,70,90 |
| Discharge Efficiency [%] | 20,40,60,80 |

Table 4 shows the attributes of the different scenarios explored, i.e., alternative power systems (Northern vs Southern), load profiles (Base vs Electrified), available firm low-carbon resources (Nuclear, Gas w/CCS, and Blue $H_2$), and weather years (Base, Higher VRE availability and Lower VRE availability). The Supplementary Information presents detailed procedures used to develop the electricity demand and wind/solar inputs for each of these scenarios, including using a cluster-approach to characterize spatial variability in wind resources (see section on "Variable Renewable and Demand Assumptions"). These profiles are typical of New England (for the Northern system) and Texas (for the Southern system) and are selected in order to explore the impact of variation in latitude, air conditioning, heating demand and other related meteorological conditions on LDES system value and capacity deployment. Note that we are not modeling with realism the New England or Texas power systems in this study, and findings should not be interpreted as indicative for planning in these regions. Supplementary Figure SI-45 shows the different duration curves for the solar and wind profiles used for the base weather year for each system. Supplementary Figure SI-46 shows the different duration curves for the solar and wind profiles used for the higher and lower VRE availability years for the Northern system. Supplementary Figure SI-47 shows a comparison of the base and higher electrification profiles for the Northern system.

**Table 4.** Scenario Definitions

| Scenario # | System | Load/ Weather Condition | Firm Resource | VRE & Li-ion Cost | Total Demand [MWh] | Peak Demand [MW] |
|---|---|---|---|---|---|---|
| 1 | Southern | Base/ Base | Blue $H_2$ | Low | 441,166,204 | 90,735 |
| 2 | Southern | Base/ Base | Gas w/CCS | Low | 441,166,204 | 90,735 |
| 3 | Southern | Base/ Base | Nuclear | Low | 441,166,204 | 90,735 |
| 4 | Northern | Base/ Base | Blue $H_2$ | Low | 181,472,557 | 35,912 |
| 5 | Northern | Base/ Base | Gas w/CCS | Low | 181,472,557 | 35,912 |
| 6 | Northern | Base/ Base | Nuclear | Low | 181,472,557 | 35,912 |
| 7 | Northern | Electrification/ Base | Blue $H_2$ | Low | 299,950,796 | 76,619 |
| 8 | Northern | Electrification/ Base | Gas w/CCS | Low | 299,950,796 | 76,619 |
| 9 | Northern | Electrification/ Base | Nuclear | Low | 299,950,796 | 76,619 |
| 10 | Northern | Base/ Higher VRE | Gas w/CCS | Low | 181,472,557 | 35,912 |
| 11 | Northern | Base/ Lower VRE | Gas w/CCS | Low | 181,472,557 | 35,912 |
| 12 | Northern | Electrification/ Base | Blue $H_2$ | Medium | 299,950,796 | 76,619 |
| 13 | Northern | Electrification/ Base | Gas w/CCS | Medium | 299,950,796 | 76,619 |
| 14 | Northern | Electrification/ Base | Nuclear | Medium | 299,950,796 | 76,619 |

[1] Systems: Southern(ERCOT), Northern (ISONE)
[2] Load Profiles: Base (linear growth), Electrified
[3] Firm Resources: Nuclear, Natural Gas with CCS, Blue $H_2$
[4] Weather Years: Base, Higher VRE CF, Lower VRE CF
[5] Variable Renewable (VRE) and Li-ion Storage Cost: Low NREL ATB, Medium NREL ATB

In addition, we investigate the value of LDES assuming the availability of one of three firm low-carbon generation technologies, including natural gas-fired CCGT power plants with CCS, nuclear plants, and both open and combined cycle gas turbines run with hydrogen assumed to be produced from reforming of natural gas with CCS (although this option can stand in for any zero or near-zero carbon fuel with a similar cost of ~$15/MMBtu). These resources are selected to span a range from high fixed/low variable costs to low fixed/high variable costs. All cases correspond to decarbonized power systems in which only firm low-carbon resources, wind, and solar PV are eligible to contribute to electricity supplies. In order to assess the impact that different firm low-carbon resources can have on LDES deployment and system value, we test each firm resource separately, i.e., for each scenario only one type of firm low-carbon resource is assumed to be available. This experimental approach creates a more favorable (less realistic) setting for LDES, but also allows for better understanding of the impact of a specific competing firm low-carbon generation source on the system value of LDES.

In total, **14** different scenarios were constructed as shown in Table 4 and **17,920 distinct cases**, each consisting of a particular combination of LDES parameters and a scenario, were simulated in the capacity expansion framework.

This research uses the GenX model, an electric power system investment and operations model described in detail elsewhere[21]. In its application in this paper, the model considers detailed operating characteristics such as thermal power plant cycling costs (unit commitment), limits on hourly changes in power output (ramp limits), and minimum stable output levels, as well as inter-temporal constraints on energy storage. The model also captures a full year of hourly chronological variability of electricity demand and renewable resource availability. The linear programming model selects the cost-minimizing set of electricity generation and storage investments and operating decisions to meet forecasted electricity demand reliably over the course of a future year, subject to specified policy constraints. A full mathematical formulation of the model as configured for this study is provided in the Supplementary Information (see the section "GenX Overview"). Specific modifications needed to model LDES technologies are detailed in the Supplementary Information Tables SI-11 - SI-12 and Equations SI-13 - SI-**??**. As we are modeling hypothetical systems, not specific regional power systems, no explicit transmission constraints are modeled within each region. Each region includes one additional wind cluster with a high capacity factor and no maximum capacity but with implicit transmission connection costs added to the capital cost to represent a distant but productive wind resource area.

Supplementary Tables SI-2 through SI-6 show the economic and technical assumptions used in this research, which are sourced from a variety of literature sources. Where possible, input parameter values were extracted from the National Renewable Energy Laboratories (NREL) Annual Technology Baseline 2018 edition (ATB 2018)[25]. Capital cost assumptions for solar and wind generators, and Li-ion battery storage used in this research correspond to the 2045 low cost projection of ATB 2018.

In order to understand the dynamics of LDES deployment and its system effects, for each of the 14 scenarios a reference LDES “Base Case” was specified which does not include any LDES capacity deployment. Supplementary Table SI-1 presents a summary of the main results of the 14 Base Cases including the total system cost (bn$), the average cost of electricity ($/MWh), the total firm capacity deployed in the system (MW), the total wind and solar capacities deployed in the system in (MW),and the energy (MWh) and power (MW) capacities of Li-ion batteries. The bulk of the analyses presented here calculate the changes to the 14 Base Case results when LDES is added to the capacity expansion framework as an eligible resource, with different combinations of LDES cost and efficiency parameters selected from across the design space.

In order to present the results of our analysis within the limitations of two-dimensional visualizations, we introduce the following additional metrics using LDES’s energy capacity, $E$,(MWh), discharge power capacity, $P_d$, (MW), and charge power capacity,$P_c$, (MW): i) *duration*, $d$ – maximum continuous discharge at rated capacity – is calculated as the ratio of energy capacity and discharge power capacity multiplied by the discharge efficiency ($\eta^-$) (Eq. (1a)); (ii) *round-trip efficiency*, $\eta^2$, (%) is calculated as the product of charge, $\eta^+$, (%) and discharge, $\eta^-$, (%) efficiencies (Eq. (1b)); and (iii) *weighted power capacity cost*, $C_{WP}$, ($/kW) is introduced to express the charge, $c_{CP}$, ($/kW) and discharge, $c_{DP}$, ($/kW) power capacity cost in one metric. As shown in Eq. (1c), the weighted power capacity cost is calculated as the capacity-weighted sum of the discharge power capacity cost and the charge power capacity cost divided by the average power capacity of the LDES system. The

Maximum functions are needed to calculate the weighted power capacity cost in cases with no deployment of LDES capacity.

$$d = \frac{E \times \eta^-}{P_d} \tag{1a}$$

$$\eta^2 = \eta^+ \cdot \eta^- \tag{1b}$$

$$C_{WP} = \frac{c_{DP} \cdot \max(1, P_d) + c_{CP} \cdot \max(1, P_c)}{(\max(1, P_d) + \max(1, P_c))/2} \tag{1c}$$

Using the metrics shown in (1) it possible to explore our results in an LDES design space that has lower dimensionality and thus allows us to better visualize results. When the LDES technology design space parameters are projected from the original 5-dimensional space (energy capacity cost, charge power capacity cost, discharge power capacity cost, charge efficiency, and discharge efficiency) to a lower 3-dimensional LDES technology space (energy capacity cost, weighted power capacity cost, and round-trip efficiency), some features of the results cannot be observed directly. For this reason we apply a Locally Weighted Polynomial Regression (LOESS)[44] to the data to calculate smooth surfaces that can better represent trends and dynamics in our results. Finally, we map the future LDES technology projections or “future feasible regions” in Table 2 into our lower-dimensional LDES design space as shown in Supplementary Figure SI-1 differentiating between geographically constrained and unconstrained resources. For each category we construct a convex hull or feasibility line by joining the points with highest RTE and lowest weighted power cost for each resource of each category (constrained and unconstrained) at each energy capacity cost level as shown in Figure SI-2. These feasibility lines are then projected on all figures mapping the LDES design space. The resulting feasibility lines divide the LDES design space into (i) infeasible future region (the region to the left of the left-most feasibility line), (ii) geographically constrained future feasible region (region to the right of the constrained feasibility line and to the left of the unconstrained feasibility line), and (iii) unconstrained future feasible region (region to the right of the unconstrained feasible line). For energy levels where the unconstrained feasibility line reaches lower weighted power cost and higher RTE levels than the constrained feasibility line, only the former is plotted. Figure SI-1 makes clear that our LDES design space includes parameter combinations that are not identified in any of the projected “future feasible regions”. However, given the inherent uncertainty in those projections it is useful to include these larger spaces of potential future performance, in part because of the opportunity to generate useful information to inform the setting of future LDES research and innovation targets.

## Data availability

The data that support the findings of this study are available from the corresponding author upon reasonable request.

## Code availability

The code used to generate and analyze the data that support the findings of this study are available from the corresponding author upon reasonable request.

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## Author contributions statement

N.A.S. and J.D.J conceptualized the study; N.A.S, J.D.J and A.E. implemented the required model modifications; N.A.S., J.D.J., A.E. and D.S.M developed the experimental design; N.A.S and A.E. performed the model evaluations. N.A.S developed formal analysis, visualization, investigation, and produced figures. N.A.S and J.D.J drafted and finalized the manuscript. D.S.M. and R.K.L. advised on analysis and reviewed and revised the manuscript. N.A.S, J.D.J. and D.S.M responded to reviewer comments and revised the manuscript for re-submission.