CHANGING WHAT'S POSSIBLE

Duration Addition to electricitY Storage (DAYS) Overview

B. PROGRAM OVERVIEW

1. Introduction and Objectives

The Duration Addition to electricitY Storage (DAYS) program will pursue new long-duration electricity storage (LDES) technologies with discharge durations that range from 10 to approximately 100 hours at rated power. Such "long" durations are beyond the requirements for intra-day ("daily") energy time shift and many other stationary electricity storage applications common on the grid today. ARPA-E believes durations at rated power of 10 to 100 hours are relevant for needs that go beyond daily cycling but are short of seasonal energy time-shift applications. Long-duration storage applications present new forms of technical challenges associated with exceptionally low lifetime cost requirements (including both capital and operating expenses), particularly for the energy storage media and related components. However, the lower number of cumulative cycles, acceptability of slow ramp rates, and other relaxed performance requirements that are associated with long durations and infrequent cycling provide opportunities for design tradeoffs that may be leveraged to reduce costs and realize economically-viable LDES systems.

The primary objective of the DAYS program is the development of LDES systems that deliver electricity at a levelized cost of storage (LCOS) of 5 cents/kWh-cycle *across the full range of storage durations (i.e. 10 to approximately 100 hours).* This requirement results in a target lifetime cost that decreases with increasing storage duration, a marked divergence from many existing storage cost targets that focus on a single duration and thus a single cost metric. The LCOS target of 5 cents/kWh-cycle likely requires system round-trip efficiencies greater than 50%.

For this focused program, ARPA-E expects chemical, electrochemical, thermal, and mechanical technical approaches to potentially address this problem statement. The DAYS program requires that all proposed storage systems be charged by electricity alone and produce electricity as the sole output.

If successful, the DAYS program will provide new forms of stationary electricity storage systems that enhance grid resiliency, provide low-cost capacity, support the transmission and distribution infrastructure, enable a greater share of low-cost, intermittent sources of wind and solar in the future generation mix, along with other benefits.

2. Project Content, Funding Levels, and Program Schedule

ARPA-E expects projects funded through the DAYS FOA to focus on the development of sub-scale components, full-scale components, and/or sub-scale systems. Because the program is open to several technology classes, there are a range of scales for the demonstration of proof of concept and proof of performance for both components and systems. For this program, ARPA-E is open to smaller projects seeking to develop transformational advances in one or more components used in a complete system, with proof of concept demonstrated at the sub-scale component level. ARPA-E is also open to larger projects, seeking proof of concept for full-scale components, and/or a complete sub-scale system. Awards issued through the DAYS FOA will range from $500,000 to $10 million.

Regardless of whether a project focuses at the component or system level, the performance results need to be augmented with full-scale system performance and cost modeling to assess the ability of the approach to meet or exceed the program metrics once a full-scale system is built. In other words, techno-economic analysis will be required for all projects.

At ARPA-E's discretion, subject to the availability of appropriated funds, a second phase to the DAYS program is envisioned, with a goal of building one or more prototype systems that are placed in field use. Prospective recipients for any future second phase may be selected by ARPA-E for award negotiations based upon the technical and other success of any project(s) sponsored under this Funding Opportunity Announcement, as demonstrated in the Final Scientific/Technical Report. ARPA-E may also publish a Phase II Funding Opportunity Announcement, open to all eligible entities. ARPA-E expects to finalize and publicize its plans for a second phase to the DAYS program in 2021.

3. Technical Categories and Program Metrics

The DAYS program includes two technical categories, which are described in more detail in Figure 2 and Figure 3 below, along with their associated text:

- Daily-plus cycling (Category 1): LDES systems that provide daily cycling, in addition to longer-duration, less frequent cycling.
- Non-daily cycling (Category 2): LDES systems that do *not* provide daily cycling and only provide less frequent cycling.

Because this program is open to a range of different storage technology classes (including thermal, mechanical, electrochemical, chemical, and others), the technical performance targets in Table 1 of this section are necessarily high level and primarily economic. To ensure ARPA-E has sufficiently granular technical information to make informed selection decisions, the specific technical information that is required for reviewers to assess the potential for an approach to meet the metrics in Table 1 is required from Applicants in Section 1 of the Technical Volume.

Table 1. Technical performance metrics for the DAYS program.

ID	Metric name	Value	Description and rationale
1	Duration at rated power	10 to approximately 100 hours	These durations of interest are intermediate between daily cycling and seasonal cycling.
2	Levelized cost of storage (LCOS)	5 cents/kWh-cycle	Target per-cycle storage cost accounting for capital, operating (including system inefficiency), maintenance, and all other costs. A discount rate of 10% and a system lifetime of 20 years are assumed. See equation [1] and the associated discussion below for more information on LCOS.
3	Electricity purchase price	2.5 cents/kWh	An electricity purchase price allows applicants to balance operating costs with other costs (including capital expenses), with a fixed LCOS. 2.5 cents/kWh is an expected unsubsidized cost of electricity for future utility-scale wind and solar installations available through power purchase agreements or similar contracts, and is also a favorable wholesale electricity price in deregulated markets.*
4	Siting requirements	No geographic constraints	The technologies in this program need to be suitable for siting throughout the entire United States. Technologies may make use of below ground storage (e.g., a sub-surface tank), but may not rely on site-specific geologic structures.
5	Energy form for charge and discharge	Only electricity in / only electricity out	This program will only consider storage systems that are charged solely by electricity and produce electricity on discharge. In other words, the program is not interested in systems such as concentrating solar power that have photons as an input.

6	Minimum final, full-scale system size	100 kW based on peak electrical output	The minimum size is chosen to reflect the program focus on systems for commercial and utility applications.
7	Duty cycle	Applicants must use the duty cycles shown in Figure 2B, which result in the cost-duration curves shown in Figure 3.	The duty cycle is required to establish system cost targets as a function of duration. ARPA-E has proposed two duty cycles that define the two program categories.

*With a purchase price of 2.5 cents/kWh and an LCOS of 5 cents/kWh-cycle, if the round-trip efficiency is 33% there is *no* money left for capital and other costs, while with a round-trip efficiency of 50% there is 2.5 cents/kWh-cycle available for capital and all other costs. Thus, while these metrics allow Applicants to trade off capital and operating expenses, 33% is a hard lower bound on round-trip efficiency, and ARPA-E generally expects technologies funded in this program to have a round-trip efficiency of greater than 50%. Another key consideration is that as the discharge efficiency drops, the effective cost of the stored energy increases because a larger fraction of the stored energy is lost during the conversion process. Thus, the impact of efficiency is twofold.

Examples of technical approaches of interest for LDES systems with Daily-plus (Category 1) and Non-daily (Category 2) duty cycles include but are not limited to:

- Electricity storage systems that are not obvious extensions of systems currently being designed for durations of 8 to 10 h at rated power. In particular, high-risk technical approaches that are highly differentiated in their cost-performance design tradeoffs relative to current commercial and R&D electricity storage systems, for which proof of concept is required, are of interest.
- Approaches with the potential to achieve the technical performance metrics for durations up to the upper range of interest for the DAYS program, i.e. approximately 100 hours.
- Systems with an electricity storage capital cost that is a declining function of storage duration. Figure 6 in the technical appendix below provides a conceptual visualization of this approach. For example, physical, chemical, or electrochemical transformation of active materials during system operation to enable storage at higher energy density relative to that required for optimized power stack operation are of interest.
- Technical approaches that exploit the reduced performance requirements associated with less frequent cycling, while maintaining excellent calendar life.
- Approaches to significantly reduce energy and balance-of-plant costs through innovative system architectures, energy dense storage media, inherently safe bulk storage systems, and other approaches.
- Innovative approaches to leverage extremely low cost energy storage materials, and potentially even negative cost energy storage media.
- Methods to provide cost-effective thermal insulation that is required by the long dwell times associated with infrequent cycling and a need to retain system efficiency.
- Approaches that exploit the low ramp rates required for infrequent cycling that can likely be predicted well in advance, regarding both power and energy components.
- Storage systems that can leverage an existing power block (such as a turbine, or a flow battery stack) to dramatically limit the need for additional power-related costs.
- Development of energy-related subsystems that augment the duration of existing daily-cycling storage systems, but that are differentiated from the daily-cycling storage medium in physical state, composition, concentration, or other characteristic.

In the remainder of this section, additional context specifically relevant to the performance metrics in Table 1 is provided. First, a key quantity for the program is the levelized cost of storage (LCOS). The LCOS is the amount paid to a storage system for each cycle that is accomplished and can be thought of as a cost adder for each unit of energy that passes through the system. For purposes of this FOA, LCOS is defined as:

$$\cancel{LCOS = \left[\left(\frac{1}{\eta_{RTE}} - 1 \right) P_c \sum_{t=1}^{T} \frac{1}{(1+r)^t} + \sum_{t=1}^{T} \frac{O\&M(t)}{(1+r)^t} + \left(\frac{C_E}{\eta_D} + \frac{C_P}{d} \right) \right] * \left[\sum_{t=1}^{T} \frac{n_c(t)}{(1+r)^t} \right]^{-1} \quad [1]}$$

$$LCOS = \left[\left(\frac{1}{\eta_{RTE}} - 1 \right) P_c \sum_{t=1}^{T} \frac{n_c(t)}{(1+r)^t} + \sum_{t=1}^{T} \frac{O\&M(t)}{(1+r)^t} + \left(\frac{C_E}{\eta_D} + \frac{C_P}{d} \right) \right] * \left[\sum_{t=1}^{T} \frac{n_c(t)}{(1+r)^t} \right]^{-1} \quad [1]$$

where η_{RTE} and η_D are the AC system round-trip and discharge efficiencies at rated power, respectively, P_c is the input electricity price during charging, r is the discount rate, T is system lifetime in years, $O\&M(t)$ is the combination of fixed and variable operations and maintenance costs over time interval t in $/kWh (including periodic replacement of any system components), C_E is the capital cost for (usable) energy-specific components and associated balance of plant ($/kWh), C_P is the capital cost for power-specific components and associated balance of plant at rated power ($/kW), d is the storage duration at rated power (h), and $n_c(t)$ is the total number of equivalent full charge-discharge cycles the system performs over time interval t. Calculations throughout this FOA assume a fixed input electricity price of 2.5 cents/kWh, 10% discount rate, and 20-year system lifetime. As indicated by the breakdown of system capital costs into power- and energy-related components, ARPA-E expects the majority of technical approaches that can achieve the program goals to have fully decoupled energy and power. Figure 1 provides a visual depiction of the LCOS and example relative cost contributions associated with system inefficiency, operations and maintenance, and capital expenditure.

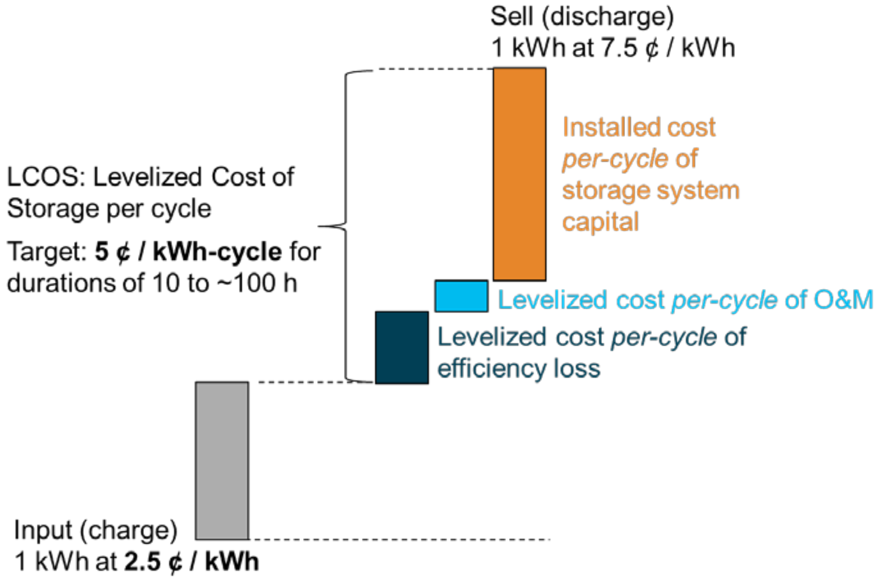

Figure 1. Illustration of economic targets for the program and one possible breakdown of LCOS. The fixed purchase price of electricity (2.5 cents/kWh) and the cost adder (i.e., the LCOS) for each kWh that is transacted through the storage asset (5 cents/kWh-cycle) are provided.

The principal target metric of the DAYS program is an LCOS of 5 cents/kWh-cycle. This aggressive metric is consistent with previous targets for daily cycling applications[1], with the key difference here being that the target LCOS *remains fixed across the entire range of durations under consideration*. In other words, the LCOS for a system with a 100-hour duration would be identical to that of a system with a 10-hour duration. The rationale for this choice is that it facilitates integration of increasing durations of electrical energy storage at a fixed per-cycle cost, thereby allowing storage systems to serve long-duration applications in which they have traditionally been cost prohibitive. As shown in Figure 2A, the implication of a fixed LCOS is that the total cost of the storage system over its lifetime, expressed on a per-unit-energy basis, must

[1] energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf

decrease as the frequency of storage system cycling decreases. This follows from the fact that the full energy stored by a long-duration storage system is accessed relatively infrequently, resulting in fewer total cycles and thus less total revenue per unit energy. The green shaded region in Figure 2A highlights the cycling frequencies and system lifetime costs of interest for the DAYS program.

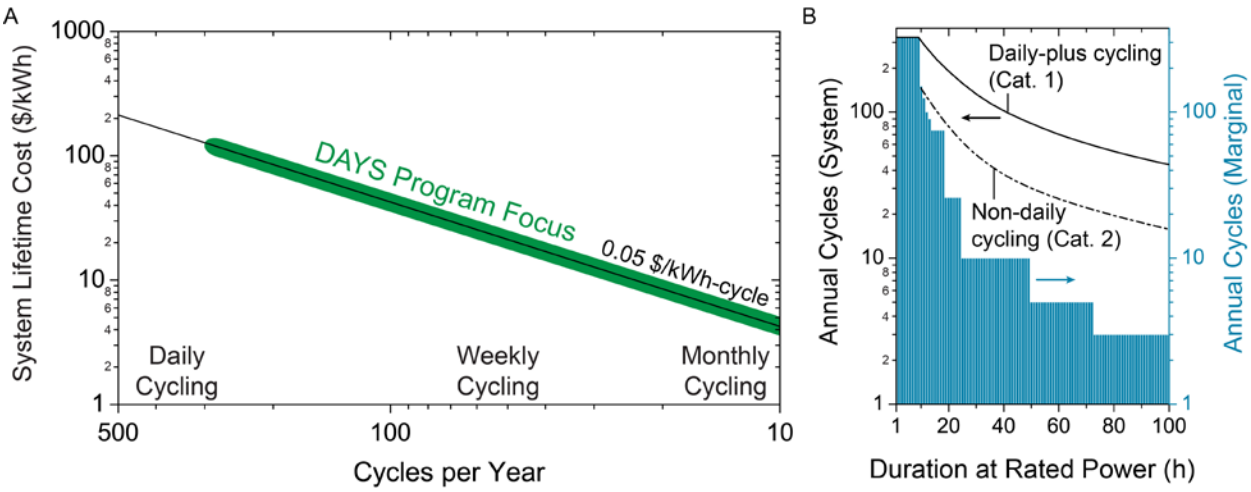

Figure 2. (A) Graphical representation of the decreasing system lifetime cost requirement as a function of the cycling frequency. The green highlighted region indicates the annual system cycle counts and lifetime costs of interest for the DAYS program. (B) Assumed duty cycle used to correlate cycle frequency and storage duration. Blue bars indicate the number of cycles each marginal hour of the storage system performs per year. The black lines represent the total cycle count for a system that cycles daily and beyond daily (solid line, Category 1) and a system that is only operated beyond daily (dashed line, Category 2).

Storage systems are typically designed and rated according to their energy-to-power ratio, in units of hours. Thus, it is important in the context of the DAYS program to also examine target costs as a function of duration. Converting from cycles per year to storage duration requires specification of a duty cycle for the system. The duty cycle ultimately derives from both the application(s) served and the system design. Relevant aspects of a duty cycle include the rate of charge and discharge (which often may be a fraction of the rated power), the depth of discharge during cycling, the dwell time spent at different states of charge, the operating temperature of the system, and other factors. ARPA-E is fully aware that there are numerous types of duty cycles, which in turn have implications for system economics. However, for the sake of this program, the duty cycle shown in Figure 2B will be used. This duty cycle is meant to be representative of a possible wind or solar firming application that maximizes use of the power block for a 100-hour system when the system cycles both daily and at less frequent intervals. The blue bars in Figure 2B indicate the number of cycles each marginal hour of the storage system performs per year, and sharply decrease at longer durations. The black lines are the total system cycle count, equal to the energy throughput for a given system per year normalized to the energy storage content at rated power. The solid line is relevant for Category 1 storage systems that include daily cycling as well as a diminishing number of cycles at longer durations. The dashed line is derived by excluding daily cycles (*i.e.*, the first ten hours) when calculating total system cycle count and reflects the lower annual cycles for Category 2 systems. While the duty cycle is not rigorously derived from one or a set of specific use cases, it points to a new design space for stationary electricity storage.

Figure 3 uses the duty cycle shown in Figure 2B and quantifies the implication of a fixed LCOS across duration; *it is the key figure for the DAYS program*. Several points are important to call to attention. *First*, note that the system lifetime cost on the y-axis here is *not* the capital cost, but is derived from equation [1], and therefore *includes* capital costs, costs associated with system inefficiency, as well as other costs. Capital cost requirements are therefore *lower* than the values shown in this figure, and Applicants can explore tradeoffs between the costs associated with system inefficiency and capital costs, along with the other costs shown in equation [1]. *Second*, the gray box in the upper left corner shows the current costs and durations for new commercial installations (predominantly Li-ion). The durations are far shorter, and the costs higher, than the focus of the DAYS program. *Third*, system lifetime cost as a function of duration for two important baseline technologies – pumped-storage hydropower (PSH) and future Li-ion – are shown.[2] At shorter durations, the value of Li-ion is clearly demonstrated, with costs below those of PSH up to durations of approximately 4-6 hours. The cost structure of Li-ion (with power costs coming from an inverter) is advantageous at durations of approximately 5 hours and less. However, Figure 3 shows that the cost structure of future Li-ion is fundamentally different than that of PSH at longer durations, as a result of a higher installed energy cost (optimistically assumed to be ~150 $/kWh for future Li-ion vs. ~2 $/kWh for PSH). *Fourth*, the figure shows the cost goal for daily cycling (Category 1) of the DAYS program. As described previously, Category 1 is for systems that accomplish *both* daily cycling (and therefore receive the high revenue streams associated with frequent use) *and* cycling at longer durations (and hence lower frequency). Clearly, the cost structure of Li-ion is fundamentally unable to achieve the Category 1 cost goal, while the cost structure of PSH meets and even exceeds the goal across the full range of durations of interest. Unfortunately, as discussed in the Technical Appendix, PSH projects have essentially ceased because of siting limitations and the uncertainty and cost of financing very large projects. And *fifth*, Figure 3 shows the cost goal for non-daily cycling (Category 2). Category 2 is for systems that are not required to provide daily cycling. They therefore miss out on the significant daily revenue stream, but also have less stringent performance requirements (e.g. cycle life and round-trip efficiency), which opens a new cost-performance design space for stationary storage systems. The cost targets for Category 2 begin at the 10 h duration mark in Figure 3, which reflects the fact that the values were derived by summing the revenues only beyond 10 hours (i.e. excluding daily cycling) according to the duty cycle in Figure 2B. However, Category 2 systems and subsystems do have a "first hour" of energy storage with respect to their operation. More information on system cost analysis is included in the Technical Appendix below.

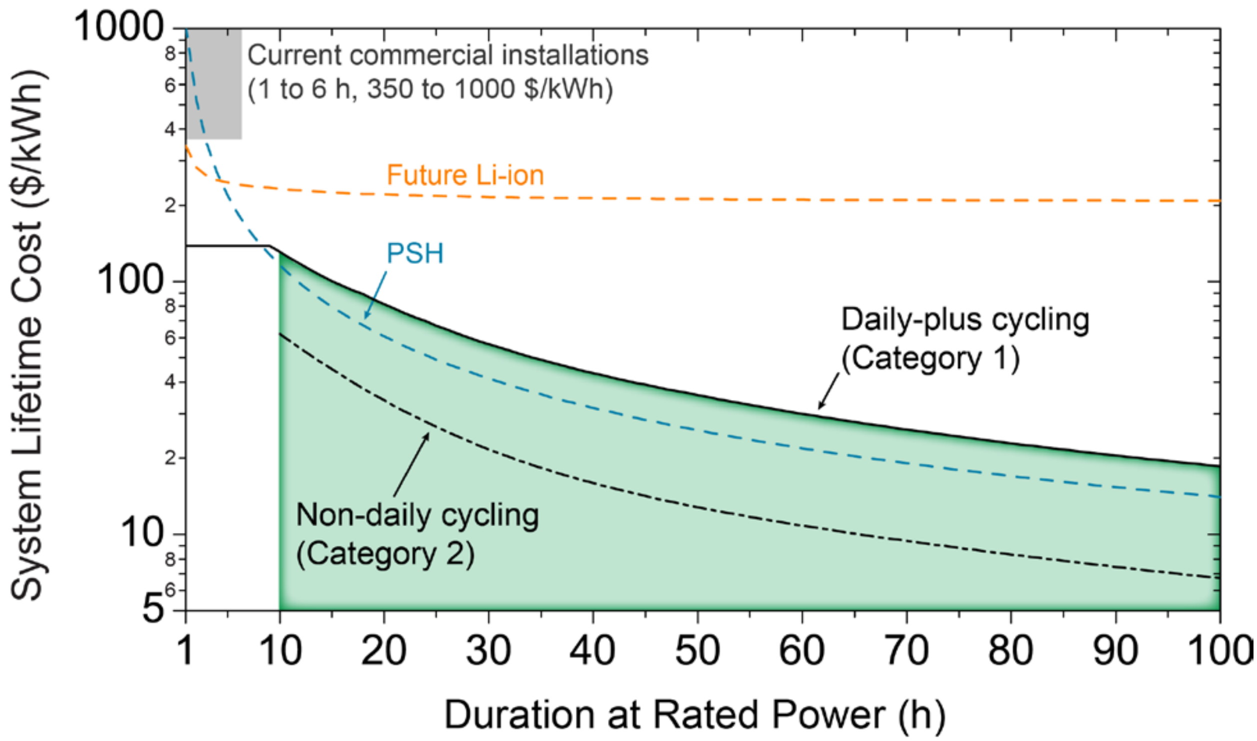

Figure 3. The key figure that defines the opportunity pursued in the DAYS program. The Category 1 and 2 goals correspond to a *fixed LCOS of 5 cents/kWh-cycle across all durations* and result in a falling system lifetime cost as the duration increases. Current commercial practice and the scaling of both Li-ion and PSH are indicated for comparison against program goals.

Finally, ARPA-E has specified an input electricity price of 2.5 cents/kWh for this program. With a fixed value for both the purchase price of electricity and the LCOS, Applicants can explore tradeoffs between the costs of system inefficiency, capital costs, and other costs. The choice of 2.5 cents/kWh reflects an estimate of future power purchase agreement

[2] Lifetime cost is calculated using LCOS according to equation [1] and the duty cycle in Figure 2B. Relevant assumptions for PSH are: η_{RTE} = 85%, η_D = 92%, P_C = 0.025 $/kWh, fixed $O\&M$ = 2.50 $/kW-y, no replacements over 20 year project, C_E = 2 $/kWh, C_P = 1000 $/kW. And for future Li-ion batteries: η_{RTE} = 81%, η_D = 90%, P_C = 0.025 $/kWh, fixed $O\&M$ = 5.00 $/kW-y, replacement cost of 150 $/kWh, and a cycle life of 5000 cycles.

(PPA) prices available to electric utilities and other buyers of wholesale electricity. Customers paying distribution expenses will always pay far more than 2.5 cents/kWh, so this goal is reflective of prices only accessible to large-scale and transmission-connected entities.

4. Technical Appendix

This section provides background and context on stationary storage and ARPA-E's interest in LDES systems, as well as technical context relevant for potential Applicants to the DAYS program.

General background on electricity storage and its applications on the grid

Stationary electrical energy storage is widely recognized to play an important role in the present United States electricity system, and has the potential to play a significantly larger role in the future.[3] Pumped-storage hydropower is by far the largest source of electricity storage on the grid today, consisting of about 22 GW of capacity and several hundred GWh of stored energy.[4] A typical discharge time for a PSH facility is 6 to 10 hours, which primarily fulfills daily energy time shift applications. There have been few new PSH installations in the U.S. in the past 25 years as a result of the difficulty of permitting new sites and financing large projects, preventing the grid from accessing more of the types of services offered by PSH. Recently, battery and other electricity storage technology installations have grown, but are still a small fraction as compared to PSH (<5% on a power-capacity basis and even lower on an energy basis).

The services provided by stationary electricity storage, both by large, centralized, transmission-connected assets, as well as smaller, distributed assets, have been carefully described in a number of reports.[5] Those services include frequency regulation, peaking capacity, energy time shift (which can benefit numerous types of generation assets, including both baseload and intermittent), transmission and distribution system upgrade deferral, black start capacity, backup power, demand charge reduction, and others. Indeed, the benefits offered by electricity storage are widely recognized; the limited rate of current deployment is due to high costs, siting challenges (e.g., for PSH), and unfavorable market structures, rather than a lack of technical benefits.

At present, there is substantial commercial excitement and activity around stationary storage, largely driven on the technology side by the scale up of Li-ion batteries resulting from growing opportunities in the automotive sector. Because of their increasing economies of scale, as well as their ubiquity in a growing number of applications, Li-ion batteries are an important benchmark for stationary storage technologies, including those envisioned to provide long-duration storage services. Recent reports suggest that tens of gigawatts of Li-ion capacity will be put in service over the next fifteen years, in some cases serving as a lower cost alternative to simple-cycle natural gas peaker plants.[6] Other storage technologies, including flow and non-flow batteries and a host of other technology classes, are also being scaled up to serve market applications primarily associated with daily energy time shift. However, due to the high marginal costs of scaling the quantity of stored energy, Li-ion batteries and many other competing technologies are severely limited in their ability to economically scale to durations beyond 10 hours. Much of the Li-ion storage capacity that is expected to be added in the coming 15 years will have a duration at rated power of 2 to 6 hours.

Rationale for work on long-duration electricity storage

The vast majority of commercial electricity storage deployments, as well as research into new forms of stationary electricity storage, focus on systems with durations of under ten hours at rated power. This focus is well placed given the clear diurnal pattern of electricity load throughout the year. Several other applications, such as transmission and distribution upgrade deferral and demand charge management, also show strong daily patterns.

However, there are several electricity storage applications that would benefit from durations substantially longer than ten hours. Backup power is one example in which tens of hours of electrical energy storage would provide critical services

[3] http://www.sandia.gov/ess/publications/SAND2010-0815.pdf

[4] https://www.eia.gov/todayinenergy/detail.php?id=31372

[5] http://www.sandia.gov/ess/publications/SAND2010-0815.pdf

[6] Manghani, Ravi, "Will Energy Storage Replace Peaker Plants?," March, 2018, gtmresearch.
Lubershane, Andy, "Following the Grid Storage Current: Technology, cost, economics," April 8, 2016, IHS Energy.

during an extended grid outage associated with a storm or other event. Extended backup power is typically served today with natural gas or diesel generators designed to solely provide backup capacity.

Another important application for LDES is the integration of large amounts of intermittent wind and solar in a future (ca. post-2030) regional electricity grid. Onshore wind and solar photovoltaics (PV) are now the cheapest forms of new electricity generation in the United States. In favorable locations, the future unsubsidized levelized cost of energy (LCOE) of these technologies will be at or below 2.5 cents/kWh.[7] These low prices for wind and solar create a substantial opportunity for the United States, through the reduction in electricity bills and through an increase in the ability to maintain low natural gas prices for use in the chemical industry or for export. However, wind and solar, with their characteristic intermittency, do not provide dispatchable power output. Strategies to mitigate inherent fluctuations in variable renewable generation must therefore be implemented on a large scale if these resources are to be used extensively on the grid while maintaining resiliency and reliability of the network. Widely accepted approaches to manage variability and uncertainty and increase the penetration of wind and solar generation include energy storage, transmission expansion, curtailment, and load flexibility. Each method has unique advantages and limitations, with cost being the longstanding challenge for stationary electricity storage, particularly as systems are scaled to increasingly greater amounts of stored energy and longer durations. The relative importance of storage versus other approaches will depend on the costs of storage, geographic region (where resources such as transmission capacity differ), policy, and other factors.

Numerous modeling studies have demonstrated that electricity storage systems with up to approximately eight hours of duration can significantly increase the amount of energy from wind and solar that can be utilized on a large regional grid (e.g., CAISO or ERCOT).[8] Most studies of high wind and solar penetrations consider levels up to about 50% on an annual energy basis, and often include simplifying assumptions such as large-scale geographic averaging, lossless and limitless transmission, and perfect generation forecasting. Despite these idealities, it is clear that increasing the duration of electricity storage will allow greater penetration of low-cost wind and solar resources. As a corollary, achieving high levels of variable renewable penetration requires multi-day electrical energy storage and even seasonal energy arbitrage in extreme cases.[9] However, additional modeling work is needed to accurately quantify the impact of LDES on wind and solar penetration at the regional level, and should include realistic handling of grid power flow constraints, network stability, contingency requirements, opportunity costs of curtailed energy, limits to load flexibility, and other parameters necessary to capture the full complexity of delivering power within a large electricity system.

An alternate opportunity for LDES systems is firming of individual wind and/or solar installations. Highly dispatchable variable renewable generator-plus-storage assets, enabled by substantial quantities of stored electricity and proper sizing of power components, would provide significantly more value to the grid compared to today's co-located systems that are typically limited to storage durations of 4 to 6 hours or less.[10] This application is likely to be more near-term relative to operation as standalone, transmission connected LDES assets. Depending on the location (e.g., Maine vs. Arizona), asset type (e.g., solar vs. wind), and desired output shape (e.g., peaker vs. baseload), storage systems with tens to approximately 100 hours of duration can in many cases deliver the desired output across greater than 90% of the hours in given year (assuming rated power of storage is commensurate with the desired output power).[11] Long-duration storage thus has the potential to grant wind and solar PV resources a character similar to baseload and dispatchable fossil fuel generators.[12]

In summary, ARPA-E sees some applications that for the right performance and cost would be interested in long-duration storage products immediately (e.g., backup power, off-grid applications, dispatchable solar or wind installations), while other applications (e.g., large-scale, grid-tied LDES systems) may not see significant market demand until further into the future.

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[7] https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf
https://www.energy.gov/sites/prod/files/2016/12/f34/SunShot%202030%20Fact%20Sheet-12_16.pdf

[8] https://www.nrel.gov/docs/fy16osti/66595.pdf, https://doi.org/10.1016/j.enpol.2011.01.019,
DOI: 10.1038/nclimate3045

[9] DOI: 10.1039/c7ee03029k

[10] https://www.pv-tech.org/news/aes-and-kiuc-break-ground-on-hawaiis-largest-solar-plus-storage-system

[11] https://arpa-e.energy.gov/sites/default/files/1c_Ferrara_2017_1207%20ARPA-E%20Workshop%20TE%20Presentation%20With%20Back-Up.pdf

[12] In terms of effective load carrying capacity (i.e. the derating of the power of a generator relative to a perfect generator in a given system) and the ability to provide power reliably within a predetermined generation profile.

The economics and operation of long-duration electricity storage systems

The range of possible storage applications, each with its own unique value proposition, complicates stationary electricity storage economics. Moreover, it is possible to "stack" multiple storage services, resulting in a new duty cycle that superposes the contributions of several individual applications. In deregulated markets, the locational marginal price of wholesale electricity also varies over time, and it is necessary to forecast future market prices when deciding when to buy and sell in the case of energy arbitrage.

While ARPA-E is fully aware of the variety of value streams available to storage, the metrics in this program are based on a single levelized cost of storage (LCOS) target, as defined in Section B.3 equation [1] above. This equation represents high level economic considerations for storage costs. Applicants should carefully consider how the underlying physical properties and characteristics of their proposed approach influence each of the relevant parameters in equation [1]. Where appropriate, Applicants are encouraged to consult established technoeconomic analyses available for various storage classes, including redox flow batteries, various types of thermal storage, and mechanical systems, to ground system-specific assumptions for cost and performance.[13]

To provide a concrete example of the implication of achieving an LCOS of 5 cents/kWh-cycle across durations up to 100 hours, if half of the electricity produced by a wind or solar plant at 2.5 cents/kWh LCOE passed through a co-located storage device with an LCOS of 5 cents/kWh-cycle (i.e. discharge price of 7.5 cents/kWh-cycle), the overall cost of electricity from the combined generator plus storage system would be 5 cents/kWh, a price expected to be competitive with electricity generated by future combined cycle natural gas plants.[14] With 90% flowing through the storage asset, the combined LCOE would still be competitive at 7 cents/kWh. With a fixed LCOS across durations up to 100 hours, these costs would result in new classes of generation assets with dispatchability over time scales of days, even without the input of additional wind or solar energy.

The opportunity defined in Figure 3 can be broken down in terms of the design space for power and energy system lifetime costs, as shown in Figure 4. Note that the power and energy costs are on a system-lifetime basis, and therefore include the installed capital cost, operation (which includes the cost of electricity lost in system inefficiency) and maintenance associated with these components, and any other costs. The curves in Figure 4 were derived from the relation

$$\lambda_P = (\lambda_T - \lambda_E)\, d \qquad [2]$$

where λ_T is the total system lifetime cost per unit energy obtained from Figure 3, λ_E is the lifetime cost of energy ($/kWh), λ_P is the lifetime cost of power ($/kW), and d is the storage duration at rated power (h). It is important to note that stationary storage cost reporting is convoluted by the fact that total system cost can be conveyed on either a per-unit-energy or per-unit-power basis by simple rearrangement of equation [2], whereas power and energy subsystem costs are always reported using their respective units. For purposes of this program, Applicants must report all system-level costs in $/kWh. As in Figure 3, solid curves in Figure 4 correspond to daily-plus cycling (Category 1), while dashed curves correspond to non-daily cycling (Category 2). Three system durations are shown for each category: 10 h, 50 h, and 100 h. The importance of energy costs for LDES systems is readily apparent, with the cost contours trending toward verticality as duration at rated power increases. In the extreme limits of duration, the system cost asymptotes at the marginal system lifetime energy cost, λ_E (i.e. the cost required to add one additional unit of energy).[15] In addition, the cost breakdown for non-daily cycling (Category 2) shows low required system lifetime power costs as well, with an upper limit of around 600 $/kW. Because of this constraint on power costs, the idea of leveraging an existing power block (for example, an existing turbine, or an existing flow battery stack), and adding on energy storage, such that the power costs are (nearly) "free," is one potential technical approach to meet the challenging non-daily cycling (Category 2) targets.

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[13] For example, DOI: 10.1039/C4EE02158D; DOI: 10.1016/j.jpowsour.2016.08.129; energy.gov/sites/prod/files/2014/08/f18/fcto_2014_electrolytic_h2_wkshp_colella1.pdf; DOI: 10.1016/j.apenergy.2016.10.045; nrel.gov/docs/fy17osti/67464.pdf; osti.gov/servlets/purl/981926; caes.pnnl.gov/pdf/PNNL-22235.pdf

[14] https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[15] DOI: 10.1016/j.joule.2017.08.007

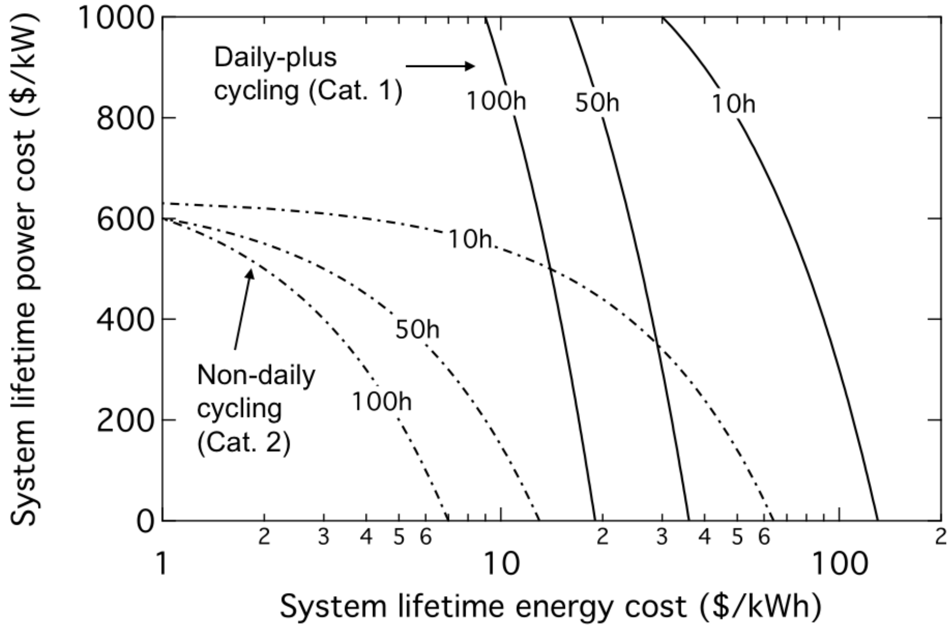

Figure 4. Breakdown of system lifetime energy and power costs for systems of various durations at a fixed LCOS of 5 cents/kWh-cycle. Cost contours for storage assets cycled both daily (Category 1) and non-daily (Category 2) are provided. Contours are derived from the full system costs shown in Figure 3 for the indicated durations. Note that costs associated with system inefficiency are proportional to energy throughput and are therefore considered part of the system lifetime energy costs.

Given the outsized impact of energy-related costs on total system costs for both categories, it is important to note that those expenses are inclusive of the energy storage medium, the container used to hold the energy storage medium, any additional balance-of-plant (BOP) costs, installation, and maintenance throughout the system lifetime. Figure 5 provides important context for two of the key cost drivers for the energy portion of a system: the capital cost of the energy storage media and capital cost of the containment. Figure 5A shows example storage media capital costs for four major classes of storage media, while Figure 5B shows containment capital costs as a function of energy density. Looking in more detail first at Figure 5A, note that capital costs are expressed on both a $/kWh and a $/L basis, and diagonal lines correspond to fixed energy densities (kWh/L). While there is not a hard cutoff on storage media capital costs, based on the system lifetime energy costs in Figure 4, capital costs in the range of approximately 5 to 20 $/kWh, depending on duration at rated power, are of interest. Figure 5A shows that a number of energy storage media can potentially meet this criterion, including some that are nearly free (e.g., rocks), common chemicals (e.g., hydrogen, ammonia, and liquid air), and some materials already used for energy storage (e.g., molten salts and an Fe-based active material used in some flow batteries, $FeCl_2$). For two common flow battery reactants – $FeCl_2$ and $VOSO_4$ – values of the energy density are shown for both the concentration typically used to flow through the stacks (~1.5M) *and* the approximate energy density when the aqueous solvent and supporting salt are removed. Removing the aqueous solvent and supporting salt is one way to increase the energy density by roughly an order of magnitude, reducing tank, BOP, and installation costs, although the cost of the energy storage media itself (on a $/kWh basis) stays roughly fixed, because the cost of the aqueous solvent and supporting salts are nearly negligible. Figure 5B shows the cost of containment as a function of energy density for several relevant containment vessels. Again, there is a not a hard cutoff on containment capital costs, but values up to approximately 20 $/kWh are of interest. Figure 5B shows the critical importance of the energy density to the containment cost, and emphasizes the importance of achieving an energy density (for all required reactants) of at least 0.1 kWh/L. For the containment of high-temperature materials requiring calcium aluminates or other materials with high strength at high temperatures, an energy density approaching or exceeding 1 kWh/L is preferable. It is also important to note that some storage approaches require secondary containment, for example if a hazardous liquid is being stored, and that must also be included in the containment cost. Overall, ARPA-E intends Figure 5 to provide Applicants with quantitative context for the design tradeoffs among capital cost, energy density, and discharge efficiency (which impacts sizing and quantity of energy-related materials and components). As a final comment, energy density is a key property because it directly influences not only the cost of containment, but also the cost of shipping, site preparation, installation, piping between containment vessels, etc.

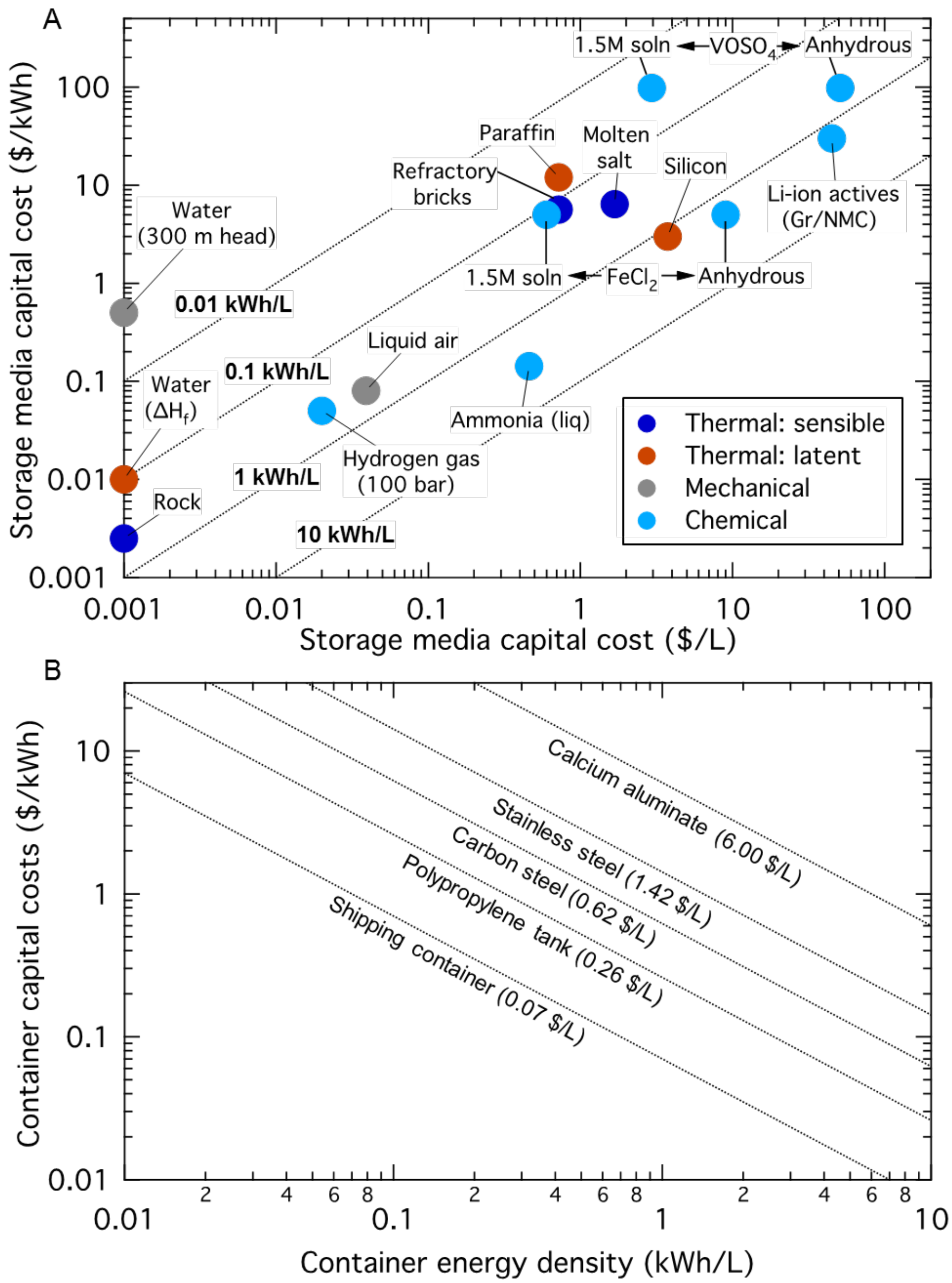

Figure 5. Overview of the capital costs for two of the key energy-related components of system lifetime energy cost. Panel A shows approximate capital costs of energy storage media, while Panel B shows capital costs of a variety of container types. The sum of these two costs should still be significantly below the system lifetime energy costs shown in Figure 4 (for a particular category and system duration) to provide budget for installation, maintenance, and other costs. Note that all of the capital costs in Figure 5 *do not* account for the discharge efficiency in the energy basis; for example, the value for molten salt is the sensible heat in the salts within its working range, not the electrical energy emerging from the power cycle.

Finally, as discussed in the list of suggestions provided in section B.3 above, one area of technical interest is the development of approaches in which the attributes of the storage units, including storage media and/or containment vessels, depend on the frequency of cycling and thus duration. Figure 6 provides a graphical depiction of such an approach, showing three energy storage attributes that change as a function of duration: energy density (which increases as a function of duration to reduce the cost of containment, installation, etc.), thermal insulation (which is required to increase as a function of duration because of the longer dwell times between cycles coupled with the need to maintain a sufficient round-trip efficiency that meets the 5 cents/kWh-cycle LCOS target), and cycle life (which can fall with increasing duration because fewer cycles are accumulated). The idea is that the increased energy density and reduced cycle life can be used to reduce the lifetime system energy cost, even while the need to increase the amount of thermal insulation adds to costs as the duration increases. The concept presented in Figure 6 may have applications to thermal, chemical, and mechanical systems, and explorations of these concepts is an area of interest for the program.

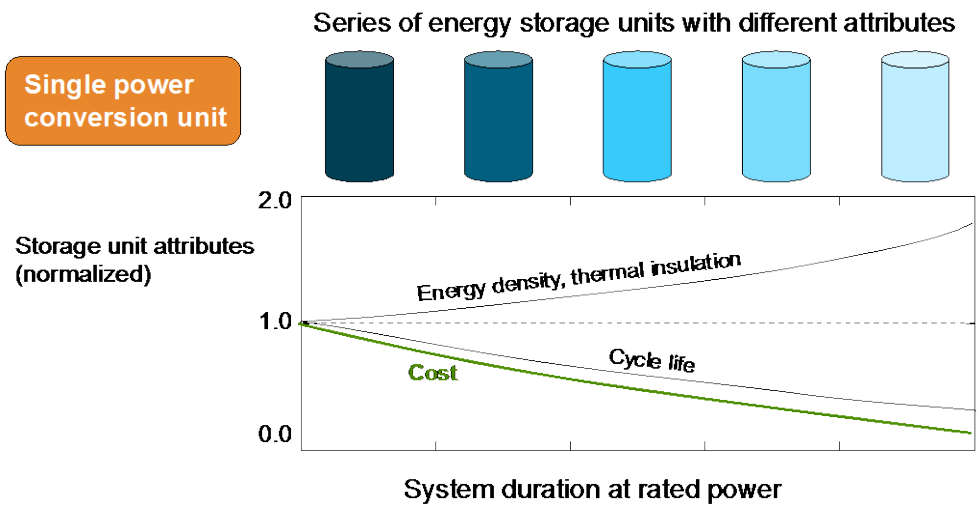

Figure 6. Schematic of a long-duration storage system with a series of energy storage units with different attributes, all sharing a single power conversion unit.