ERDC/CRREL TR-21-13

US Army Corps of Engineers®
Engineer Research and Development Center

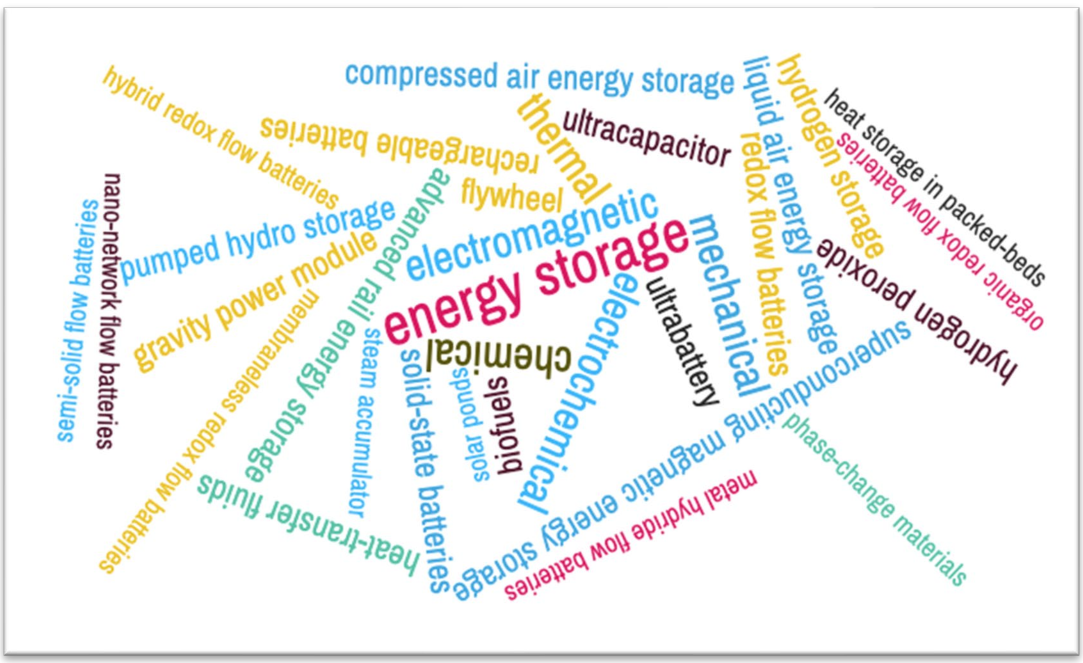
ERDC
ENGINEER RESEARCH & DEVELOPMENT CENTER

Installation Technology Transition Program

Installation Resilience in Cold Regions Using Energy Storage Systems

Caitlin A. Callaghan, Danielle R. Peterson, Timothy J. Cooke, Brandon K. Booker, and Kathryn P. Trubac

September 2021



Cold Regions Research and Engineering Laboratory

Approved for public release; distribution is unlimited.

The U.S. Army Engineer Research and Development Center (ERDC) solves the nation's toughest engineering and environmental challenges. ERDC develops innovative solutions in civil and military engineering, geospatial sciences, water resources, and environmental sciences for the Army, the Department of Defense, civilian agencies, and our nation's public good. Find out more at www.erdc.usace.army.mil.

To search for other technical reports published by ERDC, visit the ERDC online library at https://erdclibrary.on.worldcat.org/discovery.

Installation Resilience in Cold Regions Using Energy Storage Systems

Caitlin A. Callaghan, Danielle R. Peterson, Timothy J. Cooke, Brandon K. Booker, and Kathryn P. Trubac

U.S. Army Engineer Research and Development Center (ERDC)
Cold Regions Research and Engineering Laboratory (CRREL)
72 Lyme Road
Hanover, NH 03755-1290

Final Report

Approved for public release; distribution is unlimited.

Prepared for Headquarters, U.S. Army Corps of Engineers
Washington, DC 20314-1000

Under PE 131079, Project A10, “Installation Resilience in Cold Regions Using Energy Storage Systems”

Abstract

Electrical energy storage (EES) has emerged as a key enabler for access to electricity in remote environments and in those environments where other external factors challenge access to reliable electricity. In cold climates, energy storage technologies face challenging conditions that can inhibit their performance and utility to provide electricity. Use of available energy storage technologies has the potential to improve Army installation resilience by providing more consistent and reliable power to critical infrastructure and, potentially, to broader infrastructure and operations. Sustainable power, whether for long durations under normal operating conditions or for enhancing operational resilience, improves an installation's ability to maintain continuity of operations for both on- and off-installation missions. Therefore, this work assesses the maturity of energy storage technologies to provide energy stability for Army installations in cold regions, especially to meet critical power demands. The information summarized in this technical report provides a reference for considering various energy storage technologies to support specific applications at Army installations, especially those installations in cold regions.

DISCLAIMER: The contents of this report are not to be used for advertising, publication, or promotional purposes. Citation of trade names does not constitute an official endorsement or approval of the use of such commercial products. All product names and trademarks cited are the property of their respective owners. The findings of this report are not to be construed as an official Department of the Army position unless so designated by other authorized documents.

DESTROY THIS REPORT WHEN NO LONGER NEEDED. DO NOT RETURN IT TO THE ORIGINATOR.

Contents

Figures and Tables

Figures

Tables

Preface

This study was conducted for the U.S. Army Corps of Engineers and the Department of the Army, Deputy Chief of Staff, G-9 Installations, Installation Technology Transition Program under PE 131079, Project A10, "Installation Resilience in Cold Regions Using Energy Storage Systems." The technical monitor was Ms. Natalie Myers, U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL).

The work was performed by the Engineering Resources Branch of the Research and Engineering Division, U.S. Army Engineer Research and Development Center, Cold Regions Research and Engineering Laboratory (ERDC-CRREL). At the time of publication, Dr. Caitlin A. Callaghan was Branch Chief; Dr. George W. Calfas was Division Chief; and Dr. Doug Howard was the Technical Director. The Deputy Director of ERDC-CRREL was Mr. David B. Ringelberg, and the Director was Dr. Joseph L. Corriveau.

COL Theresa A. Schlosser was the Commander of ERDC and Dr. David W. Pittman was the Director.

Acronyms and Abbreviations

AC	Alternating Current
ARES	Advanced Rail Energy Storage
BESS	Battery Energy Storage System
BIGHIT	Building Innovative Green Hydrogen Systems in an Isolated Territory
CAES	Compressed-Air Energy Storage
CRREL	Cold Regions Research and Engineering Laboratory
CRREL-NH	Cold Regions Research and Engineering Laboratory's Hanover, New Hampshire Campus
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrated Solar Power
CSTX	Combat Support Training Exercise
CuO	Copper Oxide
DC	Direct Current
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
ERDC	U.S. Army Engineer Research and Development Center
EES	Electrical Energy Storage
GPM	Gravity Power Module
H_2O_2	Hydrogen Peroxide
HTF	Heat-Transfer Fluid
HTP	High-Test Peroxide
ISO-NE	Independent System Operator–New England
KEA	Kotzebue Electric Association

KNO_3	Potassium Nitrate
LAES	Liquid-Air Energy Storage
LCOE	Levelized Cost of Energy
LCOS	Levelized Cost of Storage
Li-ion	Lithium-Ion
MACRS	Modified Accelerated Cost Recovery System
MPCM	Microencapsulated Phase-Change Materials
$NaNO_3$	Sodium Nitrate
NREL	National Renewable Energy Laboratory
PCM	Phase-Change Materials
PEM	Proton-Exchange Membrane
PV	Photovoltaics
RFB	Redox Flow Batteries
RFID	Radio-Frequency Identification
SAM	System Advisor Model
SMES	Superconducting Magnetic Energy Storage
SOFC	Solid Oxide Fuel Cell
SSB	Solid-State Batteries
TA1	Training Area 1
T&D	Transmission and Distribution
UPS	Uninterrupted Power Source
VRFB	Vanadium Redox Flow Battery
WAREX	Warrior Exercise
$ZnBr_2$	Zinc Bromide

1 Introduction

1.1 Background

Electrical energy storage (EES) has emerged as a key enabler for access to electricity in remote environments and in those environments where other external factors challenge access to reliable electricity. Further, EES is also a key enabler to the use of intermittent energy resources, helping to balance the local energy system by offsetting intermittency of some energy sources, shifting load to help manage peak electricity demand, and performing other functions, often referred to as "grid services" (Gyuk 2013). EES technologies vary in terms of their function, response time, power density, energy density, and other grid services. Examples of these technologies include mechanical EES (e.g., pumped hydro, compressed-air energy storage, and flywheels), electrochemical (e.g., rechargeable or flow batteries), electrical (e.g., capacitors), thermochemical (e.g., solar), chemical (e.g., fuel cells), and thermal energy storage (e.g., heat).

Many different types of EES are currently available (mature or commercialized), and others are still being developed for different applications (Figure 1). Matching the right EES technology to a desired application requires consideration of the application's need—how much energy capacity is needed or how long the EES resource will be relied on to meet demand, for example. Figure 1 provides a sampling of the different types of EES and their level of maturity; the figure also illustrates the types of energy system challenges and relative capacity and discharge needs. Each application can present unique opportunities for EES and should be paired with a suitable (or "right") EES to meet the identified need.

In addition to understanding the capacity and duration needs for a specific EES application, it is also important to understand the lifetime, cycle life, response time, efficiency, power density, and energy density of different technologies. As an example, Figure 2 illustrates a comparison (and the diversity) of power density and energy density for different EES technologies. In applications where EES is employed as a backup to a primary electricity source, response time can be a significant characteristic; Figure 3 illustrates what is meant by "response time." The response time is the time it takes for the system to respond to receipt of a signal calling upon the system to provide power output. Response time is a function of any system delay in responding, the ramp rate at which the system outputs power to the desired level, and the recovery time from any overshoot above the desired level. In the event of an outage or elevated demand, an EES could be signaled to provide additional power output to meet the demand. If a fast response is needed, then EES technologies, such as capacitors, are likely appropriate because they can quickly discharge to provide the power output needed.

Figure 1. Capacity and duration of EES technologies. (Image reproduced from U.S. Energy Information Administration 2011. Public domain.)

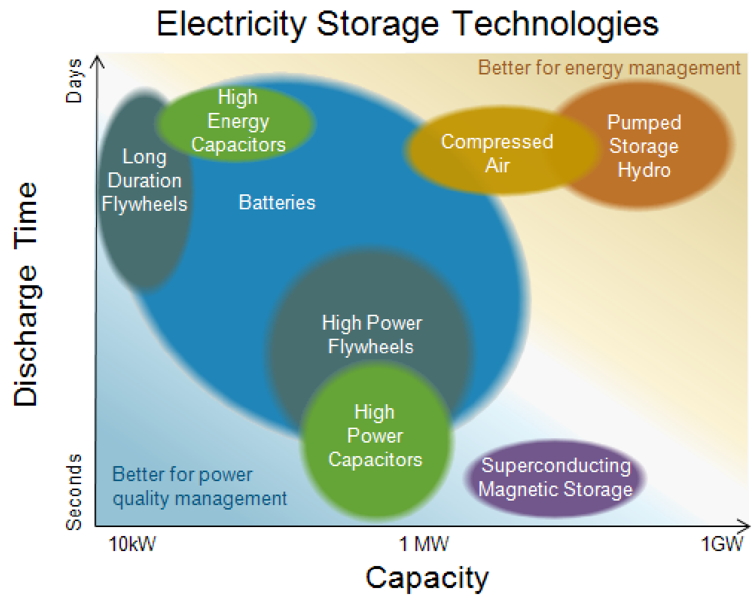


Figure 2. Energy density vs. power density for different EES technologies. (Image adapted from Kovo 2020.)

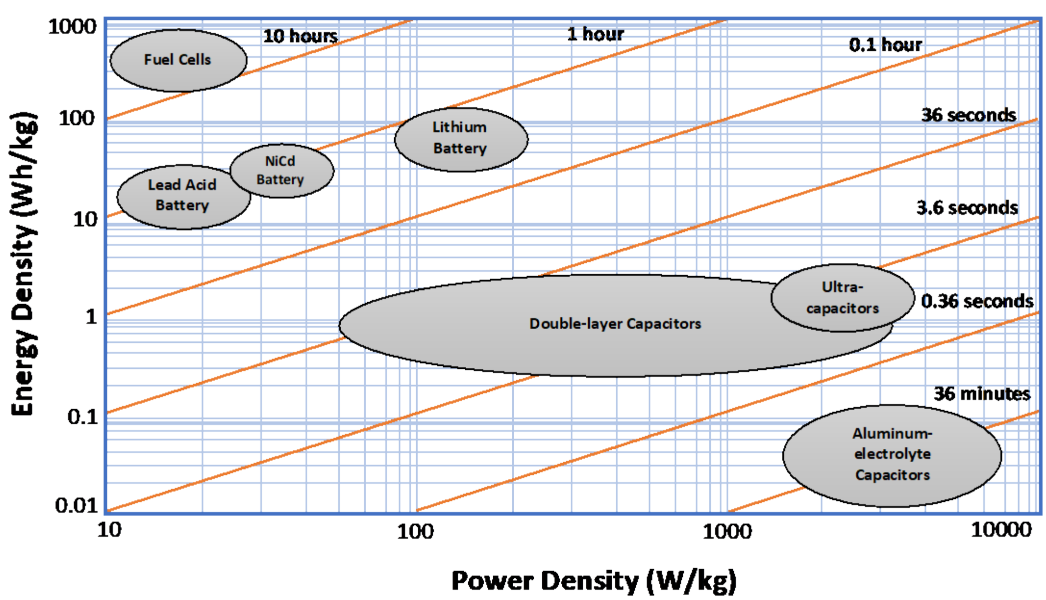
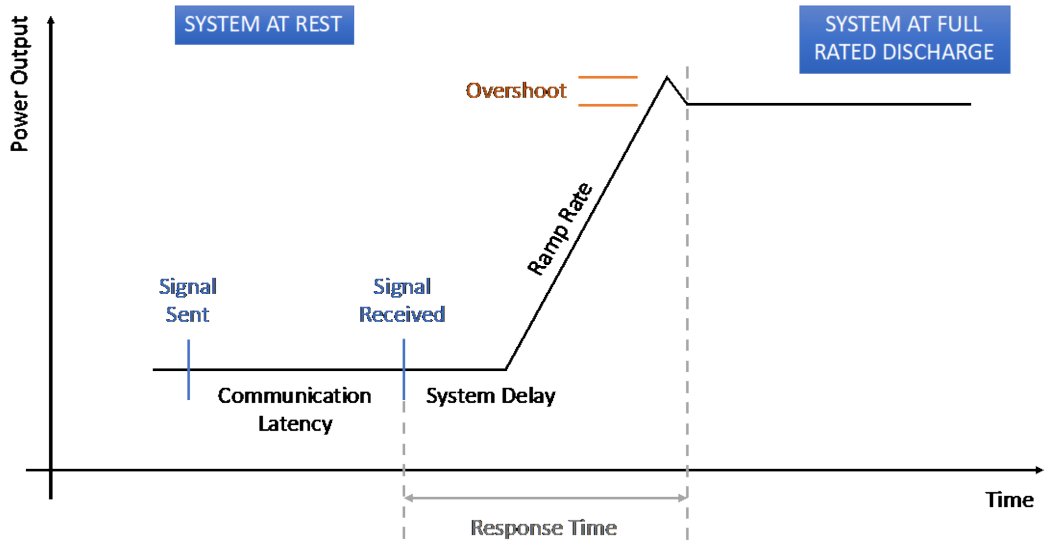


Figure 3. Response time for EES technologies.



Operating-condition limitations are another important consideration when identifying the “right” EES technology for specific applications. In cold climates, energy storage technologies face challenging conditions that can inhibit their performance and utility to provide electricity. For example, in lower temperatures, the electrochemical reactions through which electricity is generated within the battery slow, reducing power by up to 90% (Huang et al. 2000; Zhu et al. 2015). Limited energy storage technologies are available for applications in cold climates. Therefore, this work will examine the suitability of these technologies for Army installation applications, leveraging existing applications of the technologies to guide the selection of appropriate technologies based on installation demand profiles.

One such example is a system from Saft that pairs a lithium-ion (Li-ion) battery with wind and diesel generation and can operate at temperatures approaching −50°C* (Saft, n.d.). This system has been deployed in Alaska to provide continuous and stable power to the rural community of Kotzebue, displacing some of the “off-grid” community’s diesel generation dependence (Saft 2017). In 2010–2011, the Alaska Center for Energy and Power assessed the potential for vanadium redox flow batteries to provide power in support of the Kotzebue Electric Association (KEA) Premium Power Battery Project (Muhando and Johnson 2012).

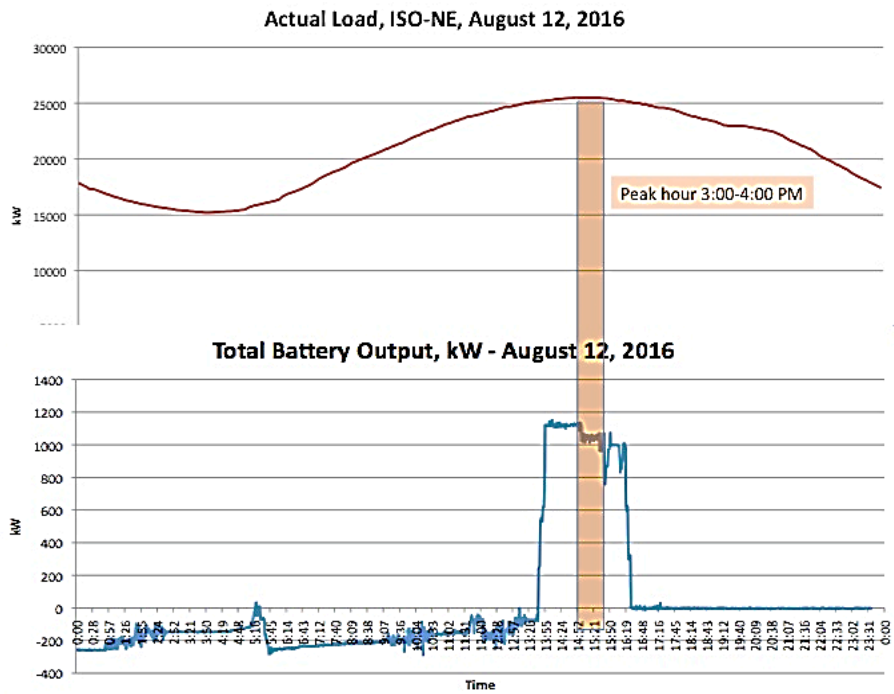
* For a full list of the spelled-out forms of the units of measure used in this document, please refer to *U.S. Government Publishing Office Style Manual*, 31st ed. (Washington, DC: U.S Government Publishing Office, 2016), 248–252, https://www.govinfo.gov/content/pkg/GPO-STYLEMANUAL-2016/pdf/GPO-STYLEMANUAL-2016.pdf.

Other examples of deployed energy storage further support the technology's potential to address installation resilience in support of mission continuity. In 2014, The U.S. Army Engineer Research and Development Center (ERDC) employed a mobile hybrid power system using battery energy storage to supply power that more quickly and efficiently adjusted to load fluctuations than traditional generators (PV Magazine 2014). Li-ion batteries typically have a duration of 0.25–4 hours (typically around 1 hour) while vanadium redox flow batteries can provide power for 2–8 hours (typically around 4 hours). Nickel-cadmium batteries, installed by the local electric cooperative Golden Valley Electric Association, have been supplying supplemental power to Fairbanks, Alaska, since 2003, operating in winter temperatures of −45°C; these batteries have a lifespan of 20–30 years (Byrne 2016).

EES technologies can also provide indirect relief in support of mission operations, including reducing the need for diesel fuel and associated delivery in remote locations, which can be a risky endeavor for military personnel deployed in hostile locations (Holcomb et al. 2007). The island community of Metlakatla, Alaska, in partnership with General Electric, installed a lead-acid battery-based energy storage system in 1996 that stabilized the local electricity supply, provided backup power to the sawmill (a primary source of community employment), and eliminated the need for approximately 475,000 gallons of diesel fuel each year (Hunt and Szymborksi 2009).

Additionally, as with any technology investment, its cost-effectiveness is often a consideration. EES technologies vary in terms of investment and payback periods, but technology demonstrations show the potential for very reasonable payback periods and, ultimately, cost savings—even in in colder climates. For example, Green Mountain Power installed a solar/storage microgrid system in Rutland, Vermont, in response to resilience challenges experienced from Hurricane Irene in 2011. This project provides important grid services, including frequency regulation, and demonstrated a payback period less than the expected 8-years, based primarily on savings from avoided peak power costs where demand was met through the microgrid's energy storage capabilities (Figure 4) and on investment from the Departmet of Energy (DOE; Schoenung et al. 2017). In the figure, the Green Mountain Power system discharges battery output during the ISO-NE (Independent System Operator–New England) system peak hour to help off-set the need for power from the utility during that period.

Figure 4. Peak electricity savings from applied EES technologies. (Image reproduced from Schoenung et al. 2017. Public domain.)

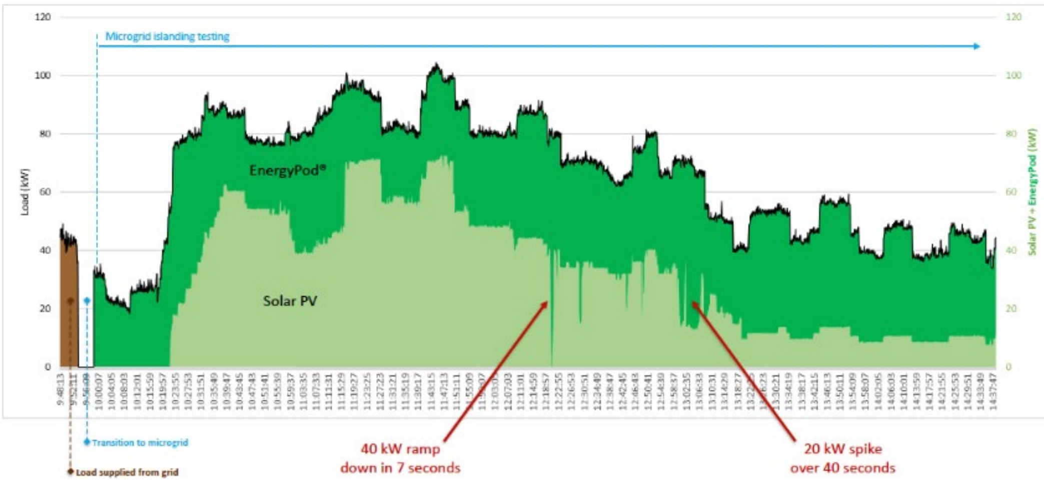


Marine Corps Air Station Miramar in San Diego, California, recently installed an on-site microgrid system with energy storage using a Primus Power EnergyPod to address high-demand charges and power outages. This technology provides energy security for the on-site facilities in addition to energy savings for the installation, in spite of the intermittent solar energy. Its performance demonstrates the utility of energy storage technologies at U.S. Department of Defense (DoD) installations (Figure 5). In the figure, the load profile is represented by the black line while the supply meeting the demand is represented by the shaded areas below the load profile. Where sharp reductions or spikes in available solar photovoltaic (PV) capacity are observed (lighter green shading), the available capacity of the EnergyPod technology (darker green shading) can compensate for these changes, helping to stabilize the overall load profile for the installation. Additionally, Figure 5 illustrates the ability for the Miramar system to island itself from the local grid supply.* The figure shows that after a brief transition period in the system (where the load profile drops to 0 kW), the load is served by the solar PV and EnergyPod technology. While islanded, Miramar is not consuming electricity from the local supplier, resulting in

* Microgrid systems can be grid connected or islanded (not grid connected). Many systems are designed to offer both options such that, when there is a disruption to the local power supply, the system can disconnect from the grid and maintain operation as if it were its own "island" power system.

energy costs savings; this is especially beneficial during peak electricity rate periods.

Figure 5. Miramar load profile with EnergyPod technology. (Image reproduced from Stepien 2017. Public domain.)



Energy storage serves many purposes as part of a facility's energy system (e.g., managing energy demand; providing cleaner, more cost-effective energy; leveraging on-site energy systems or energy streams through combined heat and power applications; and providing reliable electricity for critical infrastructure susceptible to power-quality changes and other disruptions). For Army installations in cold regions, energy storage enables an installation to maintain its operations capabilities, especially in remote locations, and to sustain operations during system outages (e.g., backup power) or during power-quality variations, which may affect sensitive or critical equipment. The Marine Corps Air Station Miramar in San Diego, California, illustrates how energy storage can help maintain operations during such occasions; in 2011, a power outage resulted in cancelled missions, grounded flights, and identified operational challenges with 25% of the diesel generators. In 2014, the Marine Corps Air Station completed the installation of a zinc-bromide ($ZnBr_2$) energy storage system to provide mission-critical backup power, as well as islanding and peak-shaving capability (Gyuk 2013). Energy storage technologies can also capture available excess on-site energy from other installation systems (e.g., heat), store it, and provide energy at a later time when called upon. Additionally, energy storage technologies can reduce energy costs and dependence on fuels that are not readily available or that increase logistical burden and can improve the environmental footprint of an installation in support of *Army Installations 2025* (U.S. Army 2016).

1.2 Objectives

The objective of this project was to determine the maturity of energy storage technologies to provide energy stability for Army installations in cold regions. This work was informed by the critical power demands at a representative subset of Army installations and the technical ability of energy storage to meet those demands reliably. The information gained through this study will illuminate the potential for such energy storage technologies to provide enhanced reliability and resilience for critical and noncritical infrastructure.

1.3 Approach

The project team, leveraging the cold regions expertise of the ERDC Cold Regions Research and Engineering Laboratory (CRREL), reviewed currently available and nascent technologies to determine their potential to reliably provide needed electricity in cold regions in support of DoD missions. The project team leveraged a representative set of Army installations located in cold region climates—specifically, Fort McCoy, Wisconsin; the CRREL Hanover, New Hampshire, campus; and the CRREL Permafrost Tunnel Research Center, Fox, Alaska—to identify mission infrastructure at the installations that can benefit from an energy storage system coupled with available on-site generation (this may include renewables, if available, for connection to an energy storage system). The identified installations provide diverse applications for this project (e.g., different climates, different operational demands, and different levels of remoteness). As appropriate, the project team's analysis identified needed capabilities missing from available technologies, potentially informing future public and private research and development efforts. Examination of such a set of applications will yield broader applicability of the findings from this work.

For the identified set of Army installations, the project team worked with the installations to understand the performance requirements for purposes of this project, leveraging available energy data. The installations selected were expected to have different installation energy profiles based on their location, their function, and their infrastructure elements; this diversity will allow broader applicability of the outputs from this project to other installations. The project team identified appropriate energy storage technologies to meet the demand based on each installation's power requirements, leveraging information evaluated about existing energy storage applications. Using the identified energy storage technologies, the project team considered different investment opportunities for each of the installations that consider the costs and benefits of implementing the technology to meet a specific need at the installation.

Finally, the lessons learned from conducting the analysis for this project will be used to document data and metrics to inform decisions regarding the feasibility of different energy storage technologies to meet an installation's electricity requirements.

1.4 Impact to the Army

Installation of available energy storage technologies has the potential to improve Army installation resilience by providing more consistent and reliable power to critical installation infrastructure and, potentially, broader infrastructure and operations. Sustainable power, whether for long durations under normal operating conditions or for enhancing operational resilience, improves an installation's ability to maintain continuity of operations for both on- and off-installation missions. Understanding the suitability of the existing EES technologies to meet critical Army installation needs is paramount for acquisition decisions to ensure that appropriate technologies are deployed, based on the need and available resources. This work will provide appropriate guidance to inform such decisions and serve to direct future work to enhance energy storage capabilities in the world's cold regions. Policy applications for military-owned utility systems, privatized utilities, and third-party-financed renewable energy projects should reflect the best technical strategy for optimizing performance and assurance of lifecycle effectiveness.

2 Literature Review

The underlying design of an energy storage system enables its various supporting roles in the connected electricity system; for example, certain energy storage technologies can more efficiently respond to short-term disruptions requiring frequency regulation (Kirby 2004). In other cases, during system outages, an installation may need to island itself (e.g., disconnect) from the local electricity system to maintain operations. This dynamic is an important consideration with respect to identifying appropriate energy storage opportunities for installations. Table 1 provides example grid service applications for select EES technologies.

Table 1. Duration, maturity, and applications of select EES technologies. (Adapted from Jain 2017).

Storage	Duration (hr)	Maturity	Application
Pumped hydroelectric	6–10	Mature	Load leveling Peak shaving Renewable integration
Compressed-air energy storage	20	Commercial	Load leveling Renewable integration
Flywheels	0.25	Commercial	Frequency regulation
Advanced lead-acid batteries	4	Demo	Power quality Frequency regulation Voltage support Renewable integration
Li-ion batteries	0.25–1	Commercial	Power quality Frequency regulation
Sodium sulfur	7.2	Commercial	Time shifting Frequency regulation Renewable integration
Vanadium flow redox	5	Demo	Peak shaving Time shifting Frequency regulation Renewable integration

The sections that follow provide an overview of a variety of different energy storage technologies and discuss their potential for DoD or Army applications.

2.1 Electrochemical

2.1.1 Rechargeable battery

2.1.1.1 Description of technology

A rechargeable battery is any battery that can be charged, discharged into a load, and then recharged. They are composed of one or more electrochemical cells. Rechargeable batteries permeate almost every aspect of modern technology. They range from nanoscale applications to large utility installations.

2.1.1.2 Applications and services

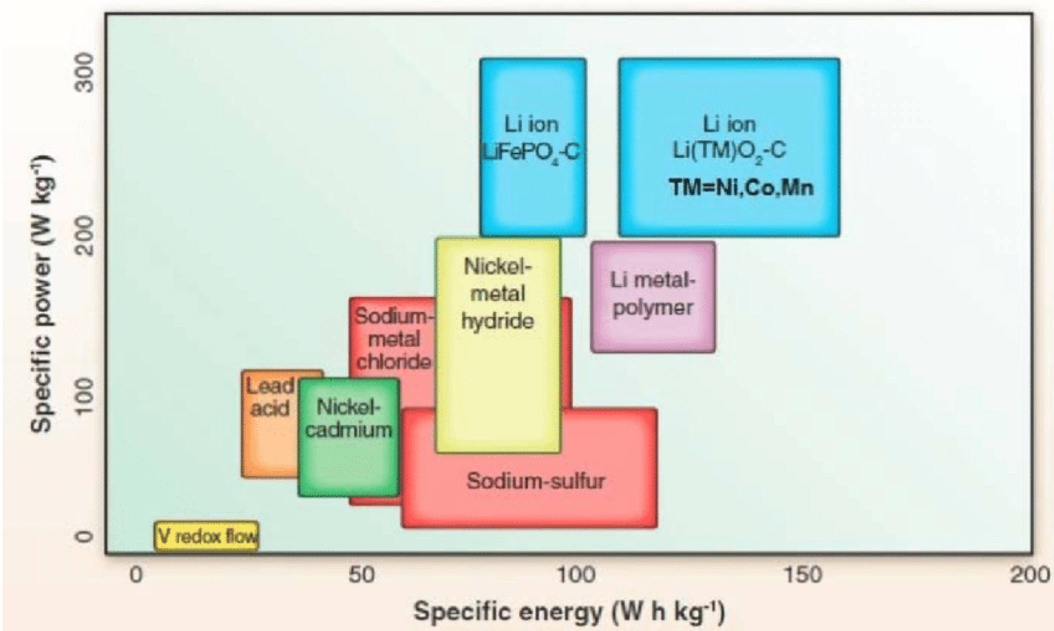
Numerous different technologies exist that cover an extremely large range of services. Table 2 lists common technologies, some characteristics, and common applications.

Table 2. Common rechargeable battery technologies.

Battery Technology	Characteristics	Common Application
Lead-acid	• Low cost • Lead and sulfuric acid	• Oldest rechargeable battery • Standard motor-vehicle battery
Nickel-metal hydride	• Nickel oxide hydroxide and hydrogen-absorbing alloy	• Electric-vehicle batteries
Li-ion	• High energy density • Slow loss of charge when not in use • Rare risk of unexpected ignition from heat generated by battery	• Mobile/handheld electronics • Vehicle batteries • Large-scale utility storage
Li-ion polymer	• Lightweight • Slightly higher energy density than Li-ion • Higher cost than Li-ion • Can be made in any shape	• Drones • Boats, helicopters, airplanes, and remote-controlled cars

Rechargeable battery technologies can act as a viable energy storage solution for a wide range of DoD and Army applications. With grid services accommodating single or multiple installations, compact energy sources for small camps and other small installations, the ability to power vehicles, and backup power for mobile bases, there exists a battery technology for nearly any size power-and energy-density need. Figure 6 illustrates the wide range of technologies that exist for various power- and energy-density needs.

Figure 6. Power vs. energy of various rechargeable battery technologies. (Image reproduced from Yang and Hou 2012. CC BY-NC-SA 3.0.)



2.1.1.3 Operating and functional limitations

Rechargeable batteries are known to be affected by extreme temperatures. At low temperatures, charging batteries such as Li-ion batteries can lead to irreversible chemical reactions inside the cells, which lead to degradation of the battery, whereas charging some batteries at high temperatures, such as nickel-cadmium batteries, leads to low oxygen saturation and a degradation of the internal chemical reaction of the battery (Battery University 2017).

2.1.1.4 Cold regions suitability

When operating rechargeable batteries in cold regions, care must be taken to ensure the battery is operating within a safe temperature range. The technology is not viable on its own when exposed to extreme cold weather. Rechargeable batteries such as Li-ion batteries can be discharged at low temperatures but cannot be recharged while cold.

Several commercial products exist, such as the Saft Batteries cold capable Li-ion system discussed in section 2.1.1.5 or other flow systems like the Primus Power EnergyPod system mentioned in section 1.1, that are marketed towards cold-weather operation with optional cold-weather packages that can be included with the system. These systems utilize heaters or temperature regulation to keep the cells of the battery within a safe operating temperature. While this extends the operational temperature range of the systems, any excess energy use needed to heat a system will lead to a loss in efficiency of the net system.

2.1.1.5 Average market cost of rechargeable batteries

The market cost of rechargeable batteries varies depending on the type of battery and its application. As of 2018, DOE reports capital costs of Li-ion batteries are on average \$271/kWh, with a total project cost of on average \$469/kWh (Mongird et al. 2019). Capital costs of lead-acid batteries are on average \$260/kWh, and total project costs are on average \$549/kWh (Mongird et al. 2019). Rechargeable batteries are a rapidly evolving field; and as the technology and manufacturing processes advance, recent years have seen a significant cost reduction. The average cost presented here is a snapshot of energy costs that are likely to differ from current pricing.

2.1.1.6 Case studies

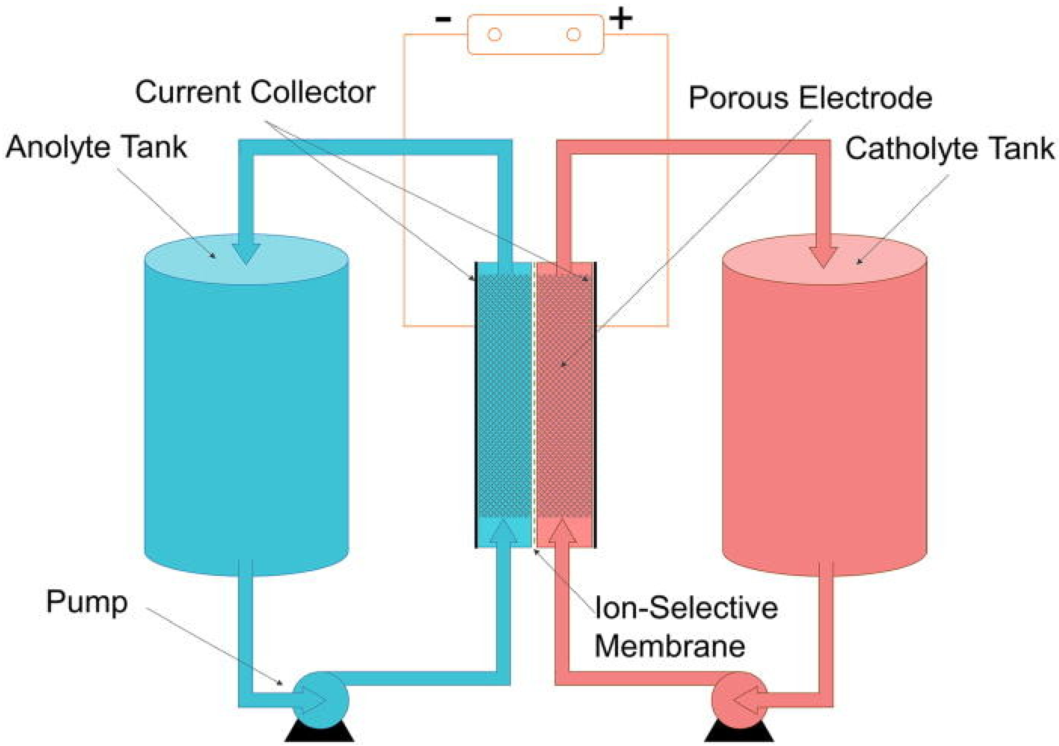
Kotzebue, Alaska, is located 30 miles north of the Arctic Circle, and temperatures in this town reach as low as −50°C. In 2015, Saft Batteries produced a low-temperature-capable Li-ion system that was fitted to the microgrid operated by KEA (Saft 2017). Saft's product, Intensium Max+ 20M, is a containerized battery energy storage system (BESS) fitted with a "cold temperature package" that combines "advanced insulation material with a hydronic heating coil . . . fed by the hot glycol solution that maintains the diesel gensets at their operating temperature" (Saft 2017). The KEA microgrid serves a community of 3700 people and combines diesel generators, wind turbines, and the new energy storage system. The BESS allows KEA to stabilize the network if wind generation ramps up or down suddenly. It also allows time-shifting excess wind output for use during higher demand or lower wind output.

2.1.2 Redox flow battery

2.1.2.1 Description of technology

Redox flow batteries (RFB) are rechargeable battery systems that store chemical energy in electrolyte solutions within a system. Ion exchange between these solutions, typically across a membrane, produces a flow of electrons. This flow can then be converted to AC power through a DC/AC (direct current / alternating current) inverter (Figure 7). These systems can be recharged because the chemical reaction that takes place is reversible; reversing the flow of the current will reverse the chemical reaction, storing the energy as chemical potential to be used later.

Figure 7. Diagram of a redox flow battery system. (Image reproduced from Qi and Koenig 2017. CC BY 4.0.)



The cell voltage of the system can be widely varied, as it depends upon the electrolytes used.

2.1.2.2 Applications and services

Because of the design of these systems, there is no theoretical limit to the amount of energy storage that is possible—energy capacity is a direct function of electrolyte volume (i.e., a larger tank means more energy can be stored). The power of these systems is also a direct function of the surface area of the electrodes—larger electrodes yield more power. Because these electrolyte solutions are stored separately and are only introduced when energy is required, they can be stored for an indefinite amount of time without any loss of energy. These types of systems function well for large, stationary applications for facilities (1 kWh to 10 MWh) (Pan and Wang 2015). This technology is applicable for DoD and Army installations requiring a large energy capacity and with the physical space necessary for large electrolyte storage tanks.

2.1.2.3 Operating and functional limitations

Physical size is the main operational and functional limitation to these systems due to the low energy density of electrolyte solutions. According to Pan and Wang (2015), “the energy density of state-of-the-art vanadium-based RFB is in the range of 20–30 $Wh \cdot L^{-1}$, which is much lower than other battery systems, such as lithium ion batteries.” Large reserve tanks of electrolyte solution are needed (hundreds of liters for 2–6 MWh of energy), making these systems impractical for small or mobile platforms.

Commercially available RFB systems use a water-based electrolyte solution. Since they are water-based, they will show a drastic reduction in efficiency as they approach their lower operational temperature limit until eventually the electrolyte solution would freeze, rendering the battery inoperable. As long as no physical damage is done to the system as a result of the solution freezing, however, the battery should operate again once it is warmed up. Research into organic-solvent-based RFBs is ongoing, but an organic RFB would not suffer from the same limitations as a traditional water-based RFB. The change in solvent allows for the use of many newer, cheaper alternative materials, which could eliminate the need for rare transition metals and further lower costs. The use of an organic solvent also allows for the use of a variety of new electrolytes that are not water soluble and therefore cannot be used in a traditional RFB.

2.1.2.4 Cold regions suitability

In cold regions, RFBs are suitable for only facility-scale installations. Low temperatures are a concern when it comes to the technology itself due to freezing concerns with a water-based electrolyte solution. A stationary installation can take other measures to insulate or regulate the temperature of the system. As long as the temperature can be maintained above the freezing point of the electrolyte solution (typically above −15°C), then the technology is a viable option. This becomes more difficult for small, mobile applications.

2.1.2.5 Average market cost of redox flow batteries

Numerous commercial RFB products exist across a wide range of power demands, many of which can come with optional cold-weather packages. As of 2018, the DOE reports capital costs of RFBs are on average

$555/kWh, with a total project cost of on average $858/kWh (Mongird et al. 2019).

2.1.2.6 Case studies

RFBs are widely utilized as storage solutions in today's market and have already been implemented in numerous facilities across the globe as energy storage solutions. They are commonly used in conjunction with renewable energy sources. The most commonly used RFB is the vanadium redox flow battery (VRFB). VRFBs are limited by their energy and power density but have extremely long lives, lasting on average between 15,000 and 20,000 cycles over 20 to 30 years (Alotto et al. 2014). They can also have very large capacities. The Minami Hayakita Substation in Japan uses a VRFB that has a rated output of 15 MW and a capacity of 60 MWh (DOE 2020).

2.1.3 Other flow battery technologies

2.1.3.1 Hybrid redox flow battery

Hybrid RFBs use one or more electroactive component deposited as a solid layer. Examples of this type include lead-acid batteries (typical automobile batteries) and zinc-bromine flow batteries. They operate much the same as traditional RFBs previously discussed and are already used across a wide range of Army and DoD applications. Zinc-bromine flow batteries have been used for large installation and facility storage; for example, the Primus Power EnergyPod was installed at the Marine Corps Air Station Miramar in San Diego, California.

2.1.3.2 Membraneless redox flow batteries

Membraneless RFBs rely on laminar flow rather than a membrane in their design. Two electrolyte solutions are pumped through a channel and undergo an electrochemical reaction, which either stores or releases energy. The laminar flow allows the two solutions to stream in parallel with little mixing, eliminating the need for a membrane. The membrane is typically the most costly and least reliable component of these systems, as they can corrode over time with repeated exposure. An example of this type of system is the liquid bromine-hydrogen gas cell. Liquid bromine-hydrogen cells cannot be used with membranes, as they form hydrobromic acid, a strong acid that would corrode the membrane material. The power density of these cells, however, has been reported to reach 7950 W/m^2, an order of magnitude higher than Li-ion batteries (Braff et al. 2013).

2.1.3.3 Organic redox flow battery

Organic-solvent-based RFBs offer several advantages over standard RFBs: they are lower in cost and they offer the ability to use organic solvents instead of water for the electrolyte solutions. Because of the ability to tune the properties of organic molecules, it is also possible to use the same molecule as both the anolyte and the catholyte, reducing possible crossover contamination and greatly increasing longevity of the system while still being more affordable than the rare metals used in common RFBs. Organic solvents have a much lower freezing point than water, so the operational temperature range of these systems could be much lower. These technologies are still relatively new, having only emerged in 2009; and more research is needed before they become a viable option.

2.1.3.4 Metal hydride flow battery

Metal hydride flow batteries, also known as proton flow batteries, are systems that integrate a metal hydride storage electrode into a reversible proton exchange membrane fuel cell. When a current is applied to the system, as when charging the proton flow battery, hydrogen ions are produced via electrolysis of water. These ions combine with electrons and metal particles in one electrode of a fuel cell. The solid-state metal hydride matrix that results from this combination stores chemical energy. When the system is discharged, ambient oxygen is mixed with these solid-state metal hydrides, producing electricity and water. New research suggests that it is possible for these systems to use less expensive, nonrare earth metals, which would reduce the cost while producing energy densities greater than Li-ion cells (Andrews and Mohammadi 2014). This technology is still new, however, and has yet to be widely utilized.

2.1.3.5 Nanonetwork flow battery

Nanonetwork flow batteries eliminate the requirement that particles come into contact with a conducting plate for charge to flow. In a standard RFB, electricity is extracted only when the electrolytes come into direct contact with the electrode, usually a flat metal plate. Comparatively, the nanoparticle network in an NNFB allows electricity to flow throughout the liquid, allowing for more energy to be retrieved as the electrical connection is maintained even as the liquid flows through the system. This technology is not yet suitable for DoD or Army applications as researchers have yet to demonstrate the longevity of these systems (Bullis 2014).

2.1.3.6 Semi-solid flow battery

Semi-solid flow batteries combine the basic structure of a flow battery with the chemistry of Li-ion batteries. Rather than distinct positive and negative electrodes, metal particles suspended in a carrier liquid act as the electrodes. Two separate tanks house the positive and negative electrode suspensions, respectively. When these suspensions are pumped into a reaction chamber, they react and produce a current. The battery system can be recharged by providing an electrical charge to the system, or it could be recharged by replacing the discharged liquid slurry suspension. This discharged suspension could then be recharged outside of the battery system. This technology has implications in the electric vehicle market, as it would be possible to simply replace the discharged suspension, much like refueling a traditional combustion engine with gas. The discharged suspension could then be recharged externally by the filling station (Chandler 2011). The necessary infrastructure for a system like this does not currently exist and is a major limiting factor to this technology's applicability for DoD or Army needs.

2.1.4 Solid-state battery

2.1.4.1 Description of technology

Solid-state batteries (SSBs) use solid electrodes and a solid electrolyte. They are typically made of ceramics (oxides, sulfides, and phosphates), solid polymers, or different types of glass rather than the liquid or polymer gel electrolytes found in Li-ion or Li-ion-polymer batteries. In these systems, the cathodes tend to be lithium based.

2.1.4.2 Applications and services

SSBs can be made very small, so they have been used in wearable devices or implanted medical devices such as pacemakers. They are also used in RFID (radio-frequency identification) technologies. They have much higher costs associated with their production when compared to liquid or polymer gel electrolyte-based batteries. By removing the flammable liquid electrolyte, SSBs offer a potentially safer alternative to Li-ion batteries. This technology is still new and has yet to show its suitability for larger-scale applications. Its value to DoD or Army applications would currently be with their use in small, wearable or implanted devices.

2.1.4.3 Operating and functional limitations

SSBs as a means for significant energy storage have yet to become available in the commercial market. Researchers continue to investigate this technology that shows promise as a new, safer, more energy-dense alternative to Li-ion batteries. In particular, these batteries would be well suited to electric vehicles, given the higher energy density and safety. Researchers with Samsung have recently published improvements to this technology, which could help transfer this technology to a viable alternative for electric vehicles (Lee et al. 2020).

2.1.4.4 Cold regions suitability

At present, SSBs are not believed to be cold-weather capable. Information about their operational temperature range is limited; but as research continues, SSB suitability for cold regions applications may change depending on cold weather performance.

2.1.4.5 Average market cost of solid-state batteries

SSBs have yet to become readily available in the commercial market.

2.1.4.6 Case studies

Since this technology is still being researched, small-scale applications are all that currently exist. There are no large, installation-scale applications; however, that may change as this technology continues to emerge.

2.2 Chemical

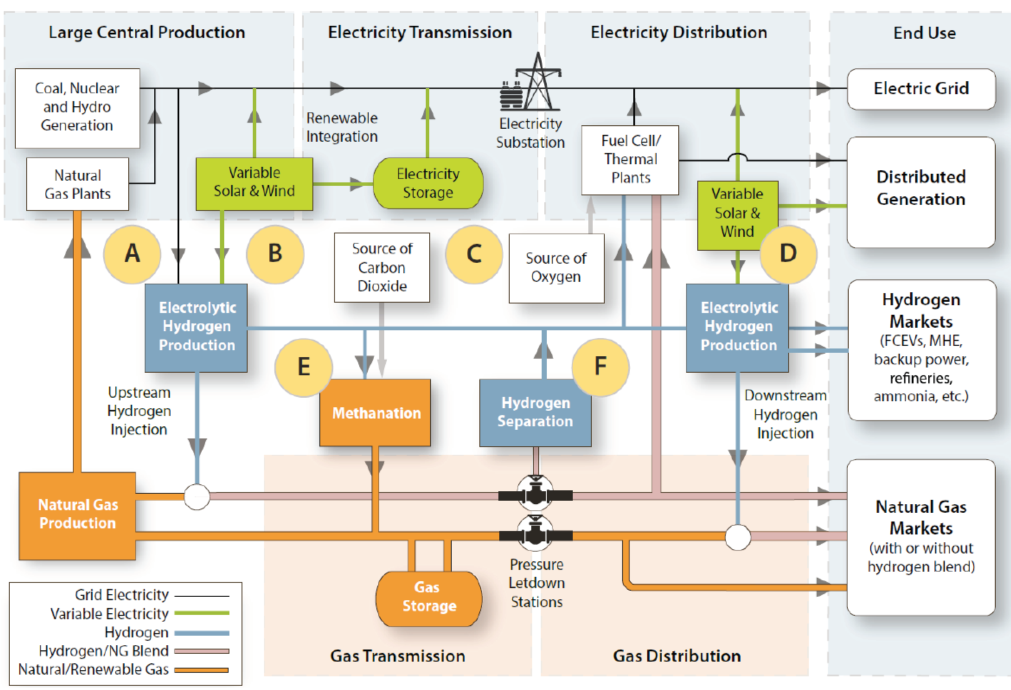
2.2.1 Hydrogen energy storage

2.2.1.1 Description of technology

Hydrogen can store chemical energy similar to petroleum, ethanol, and natural gas. Given its high gravimetric energy density (120–142 MJ/kg) (Harrison et al. 2009; Kuang et al. 2019) and its zero-hydrocarbon byproduct, the energy storage research community considers it a promising energy storage medium (Walter et al. 2010; Kuang et al. 2019). Hydrogen can be generated using energy from renewable sources, such as wind or solar, to drive the electrolysis of water into its constituents, hydrogen and oxygen (Walter et al. 2010; Z. Li et al. 2019). Most electrolysis systems use alkaline or polymer electrolyte membrane conversion processes (Barbir

2005; Harrison et al. 2009; Zeng and Zhang 2010). Hydrogen can be stored in a gaseous state in high-pressure tanks (350–700 bar tank pressure) or underground reservoirs, such as aquifers, depleted deposits of natural gas, and salt caverns (Tarkowski 2019). Hydrogen may also be stored in a liquid state to reduce its storage footprint; however, this requires cryogenic temperatures due to a boiling point of −253.8°C at one atmosphere of pressure, making the process costly (DOE, "Hydrogen," n.d.; Breeze 2019). To meet energy requirements, stored hydrogen can be converted to electricity by using a proton-exchange membrane (PEM) fuel cell or a hydrogen internal combustion engine (Harrison et al. 2009; Widera 2020). Figure 8 shows common production, storage, and energy generation pathways for hydrogen as a storage medium.

Figure 8. Process and pathways of hydrogen energy storage. (Image reproduced from Melaina and Eichman 2015. Public domain.)



2.2.1.2 *Applications and services*

Hydrogen gas can be stored on a large scale (i.e., 1 GWh to 1 TWh) for grid applications and converted to energy using combustion to generate heat to power a modified gas turbine (Staffell et al. 2019). This may allow for large-scale energy storage for peak shaving and grid balancing, but this technology is still being developed. A more practical and near-term application for stored hydrogen is balancing power supply continuity for renewables, such as solar and wind, during variable production periods (Harrison et al. 2009; Breeze 2019). Stored hydrogen can be converted to energy using a PEM fuel cell or gas turbines for application on the residential and commercial scale.

This application could benefit DoD and the Army because it is flexible, controllable, and able to be colocated with demand, providing reliable power in remote locations. Hydrogen-powered fuel-cell electric vehicles are being deployed on a commercial scale as buses, passenger cars, and truck models (Staffell et al. 2019). If the DoD or Army were to adopt this technology in their transportation equipment, on-site hydrogen generation would provide a cost-effective and abundant fuel in remote locations, assuming a steady water supply is available. These flexible applications, combined with the ability to be transported, make hydrogen energy storage a promising technology for DoD and Army energy resilience.

2.2.1.3 Operating and functional limitations

Estimated round-trip efficiencies (i.e., the ratio of energy put into storage to the energy retrieved from storage) for hydrogen storage range from 30% to 54% using the most common alkaline electrolyzers and PEM fuel cells (Pellow et al. 2015; Breeze 2019). This is low for large-scale grid applications; however, it may be acceptable for creating continuity to a renewable energy supply. This technology will become more feasible for grid applications and military installations as advancements are made in PEM electrolyzers that address energy-to-hydrogen conversion efficiencies and reduce costs (Harrison et al. 2009; Widera 2020).

2.2.1.4 Cold regions suitability

Little data exist on how hydrogen storage systems perform in extremely cold environments; however, their components have received some attention. In subfreezing temperatures, PEM fuel cells suffer from irreversible performance loss due to ice damage to the membrane electrode assembly. PEM fuel-cell system modifications, such as cold start-up of less than 75 seconds and system insulation, may alleviate these deficiencies (Datta et al. 2002; Zhan et al. 2018). Further assessments on how hydrogen energy storage systems perform in cold environments are required before this technology would be ready for DoD and Army applications.

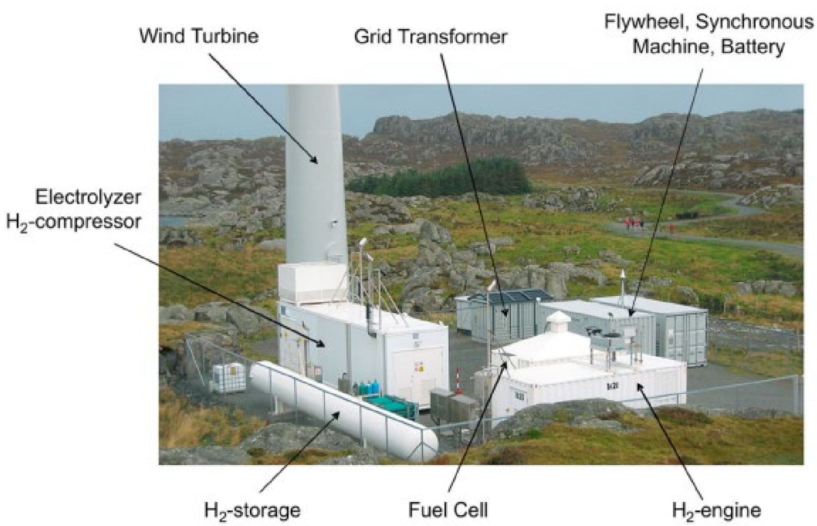
2.2.1.5 Average market cost of hydrogen energy storage

The levelized cost for hydrogen storage technology ranges from 180 to 300/MWh depending on the energy input system (e.g., wind or solar) and the output system (PEM fuel cell or hydrogen combustion turbine) (Steward et al. 2009). With the exception of pumped hydrogen and compressed air, hydrogen energy storage is already more cost-effective for discharges to meet load requirements lasting longer than 1 day (Steward et al. 2009; Schmidt et al. 2019). It is expected to become more cost-effective than compressed air by 2030 (Schmidt et al. 2019). Utilizing this technology to supplement battery storage may reduce the overall battery storage cost by 75% (Kharel and Shabani 2018).

2.2.1.6 Case studies

From 2004 to 2008, Utsira Wind Power and Hydrogen Plant operated on the Norwegian Island of Utsira (Figure 9). Utsira is a remote island in the North Sea, and weather conditions impede the delivery of fossil fuel from mainland Norway. The plant was the first full-scale combined wind power and hydrogen storage plant and was designed to assess the ability of this technology to provide reliable power to island residents.

Figure 9. The wind-to-hydrogen plant at Utsira. (Image reproduced with permission from Ulleberg et al. 2010.)



The plant had two 600 kWh wind turbines, and excess power was transferred to an electrolyzer (10 Nm3/50 kW) to generate hydrogen that was compressed and stored. A 55 kW hydrogen combustion engine and a 10 kW PEM fuel cell were used to convert hydrogen to power when the wind supply was low. The plant was capable of supplying 2–3 days of full energy to 10 residential homes on the island (Ulleberg et al. 2010).

In March of 2007, Xcel Energy and the DOE National Renewable Energy Laboratory (NREL) began the operation of their wind-to-hydrogen project located at NREL's National Wind Technology Center. The project analyzed the cost and ability to create continuity in energy supply for wind and solar by using utility-scale hydrogen storage. The project compared the performance of PEM and alkaline electrolyzes and identified that these systems do not perform well when power was supplied over their rated capacity (Harrison et al. 2009; Widera 2020). The results from the study found hydrogen to be a suitable storage medium for wind and solar energy; however, it identified a need for a more efficient and cost-effective electrolyzer (Harrison et al. 2009; Widera 2020).

In May of 2018, the project Building Innovative Green Hydrogen Systems in an Isolated Territory (BIG HIT) began hydrogen generation through water electrolysis powered by wind energy on Eday and Shapinsay Islands in the Orkney archipelago, Scotland. The project utilizes two PEM electrolyzers (1 MW and 0.5 MW) to generate 45.4 metric tons of ultrapure hydrogen. Most of the hydrogen is used to generate heat and electricity through hydrogen-powered boilers and a 75 kW hydrogen fuel cell, respectively. Additional hydrogen is transported to refueling stations to power a small fleet of zero-emission hydrogen vehicles operated by the Orkney Island Counsel (Figure 10) (Fuel Cells and Hydrogen Joint Undertaking 2020).

The conversion of stored hydrogen to electrical energy is closely tied to the use and performance of PEM fuel cells. Therefore, the following case study outlines a project that investigated the feasibility of PEM fuel cells for residential military power requirements. Between 2001 and 2004, congress funded the DoD Residential PEM Demonstration Project to assess the feasibility of PEM fuel cells ranging in size from 1 to 20 kW to meet residential energy requirements at 44 military installations (White et al. 2005). The PEM Demonstration Project researchers had oversight on the planning, installation, monitoring and maintenance of the PEM fuels cells as the researchers assessed the fuel cells' potential role to support DoD training, readiness, and sustainability missions. The PEM fuel cells were installed at DoD sites across a wide geographical range, including regions that experience colder climates, such as Montana Army National Guard, Montana, and Gabreski Air National Guard Base, New York. However, performance in cold climates was not a main focus of the report. Overall, they determined that strong communications with fuel-cell power plants will be critical to minimize downtime. They also determined that PEM fuel cells are a technically and economically realistic option as backup power for DoD applications, especially when in a hybrid configuration with a battery array (White et al. 2005).

Figure 10. Diagram of hydrogen storage and transfer in the Orkney archipelago. (Image reproduced with permission from Fuel Cells and Hydrogen Joint Undertaking 2020)

2.2.2 Hydrogen peroxide

2.2.2.1 Description of technology

Hydrogen peroxide, H_2O_2, is a potent oxidizer. When diluted, it is useful as a disinfectant; but when concentrated (30% in water), it becomes caustic, powerful enough to break down skin tissue. At extreme concentrations (70% to 98%), also known as high-test peroxide (HTP), it becomes a very reactive oxygen species and is often used as a propellant in rocketry. When HTP is pumped into a reaction chamber with a catalyst, typically silver or platinum, it rapidly decomposes into oxygen and water, in the form of steam due to the extreme energy generated in the decomposition. The steam produced is usually over 600°C. This steam can then be used to power a turbine, producing electricity, or can be directed to create thrust.

2.2.2.2 Applications and services

HTP, as a fuel source, is used primarily in the aerospace industry as a propulsion and power source (Ventura et al. 2007). It is used most as a monopropellant or bipropellant in corrective thrusters in rocketry, but can be used to spin microturbines for power for other rocketry systems (Ventura et al. 2007). It is not commonly used as a fuel source for large turbines powering a facility.

2.2.2.3 Operating and functional limitations

HTP is unstable and slowly decomposes in the presence of light. It is not easily produced at high concentrations, and its unstable nature makes delivery a concern. Once it begins to decompose, heat is released, which further speeds up the rate of decomposition, leading to potentially catastrophic failure events (Ventura et al. 2007). At concentrations over 67%, the amount of heat produced from its decomposition is enough to completely vaporize the liquid, resulting in rapid gas evolution and expansion (Ventura et al. 2007). Despite the high energy density of HTP as a fuel source, this technology is not suitable for DoD or Army applications. Specialized equipment, unique and specialized storage devices, specialized training, delivery challenges, and the generally unstable characteristics of HTP make it unsuitable for DoD or Army needs.

2.2.2.4 Cold regions suitability

The freezing point of HTP varies depending on the concentration, but 100% hydrogen peroxide has a freezing point of –1.5°C and is stable as a frozen solid. This would allow the fuel to be stored as a refrigerated solid. The issues with stability, however, are of great concern with isolated facilities that cannot afford malfunctions of their energy systems, as getting replacement parts or performing repairs could be difficult. HTP is simply too reactive and unstable to be a reliable source of energy for a facility and is much better suited to the aerospace industry.

2.2.2.5 Average market cost of hydrogen peroxide

Hydrogen peroxide, particularly HTP, as a fuel source is used in such specific aerospace applications that market cost data does not exist for an installation seeking to use this as a source of electricity.

2.2.2.6 Case studies

There are no case studies of installations using this technology as an electricity fuel supply.

2.2.3 Biofuels

Biofuels store energy within biological materials or biomass. Typically, the term biofuel refers to liquid or gaseous fuels as opposed to solid burning fuels like torrefied pellets or briquettes. If the biomass source can be regrown quickly, then the biofuel can be considered a form of renewable energy. Examples include biogas, syngas, ethanol and other bioalcohols, biodiesel, and green diesel. Common sources of biomass include energy crop plants, such as elephant grass, or agricultural, commercial, or industrial waste, provided that the waste has a biological origin. Algae and microalgae used for carbon fixation can also be processed into fuel. Biofuels can be converted to energy through combustion to power generators, engines, or similar infrastructure. They can also be mixed with traditional fuel sources like gasoline or diesel. Biofuels for an energy storage application in cold regions are not well studied, and the process of culturing and processing biomass to fuel is time-consuming and requires trained personnel. For remote military installations in cold regions, this process may not be feasible given agricultural limitations and lack of trained personnel. Additionally, in cold conditions, biofuels can thicken, causing plugged filters and supply lines (Islam et al. 2015). Given these limitations, the project team determined that biofuels are not currently a promising energy storage technology for the Army and DoD.

The DoD has investigated the use of incinerators to convert waste (e.g., biomass) to drive a steam turbine to generate electricity, as well as converting biomass to fuel for fuel cells (DOE Office of Energy Efficiency and Renewable Energy 2011; Holcomb 2008). The project team notes that this technology is used for fuel production and energy generation and, thus, is beyond the scope of this project.

2.3 Mechanical

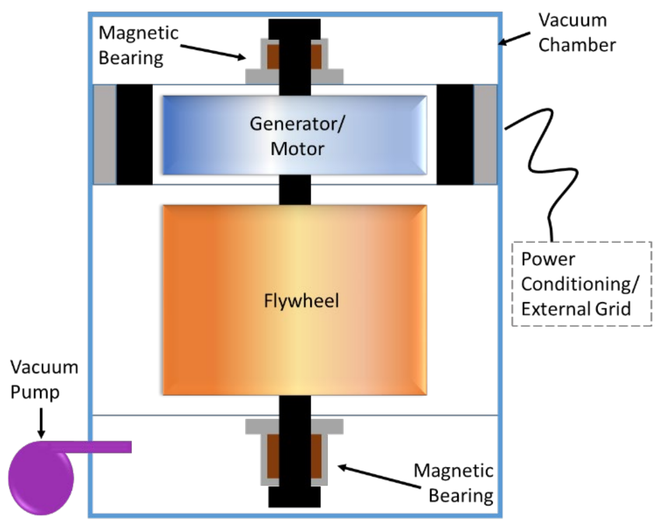
2.3.1 Flywheel

2.3.1.1 Description of technology

Flywheels store kinetic energy through a mass attached to a shaft under a rotational force. Torque may be applied to the system in a variety of ways, and the system is then discharged when a load is applied. The rotating shaft then generates electricity through an electric generator (Boicea 2014). The amount of energy stored depends on its rotational speed and inertia (Luo et al. 2015).

There are low-speed flywheels and high-speed flywheels. Low-speed flywheels are made of conventional materials like steel and rotate below 6000 RPM. High-speed flywheels use advanced composite materials, magnetics bearings, and vacuum chambers to achieve speeds up to around 100,000 RPM (Luo et al. 2015). Figure 11 illustrates a flywheel storage system.

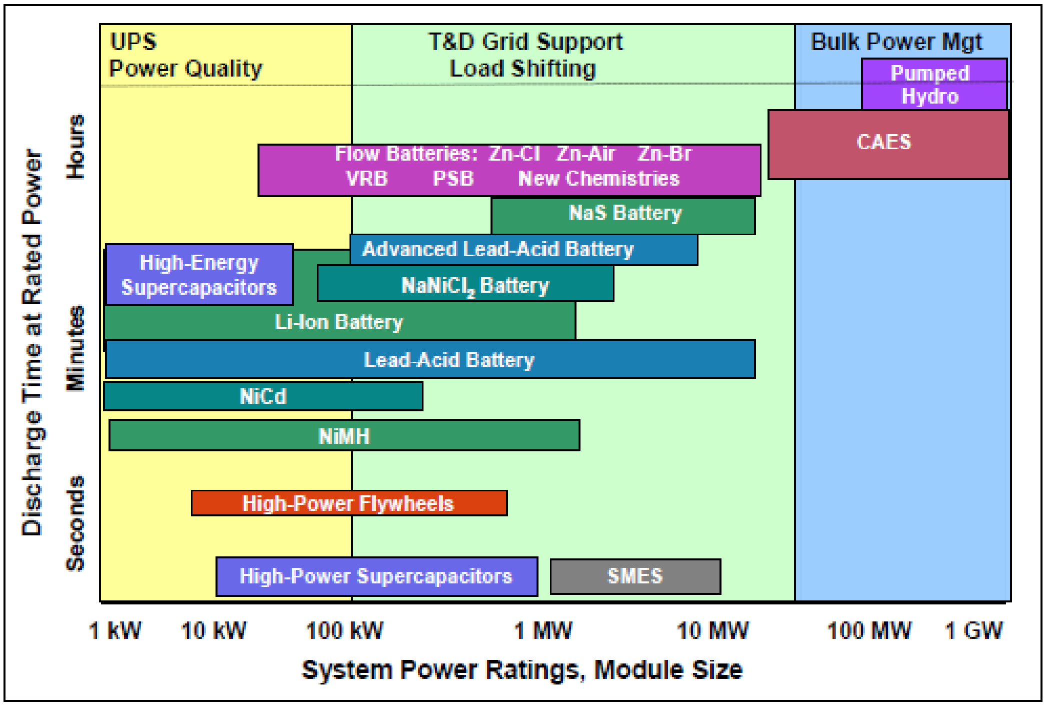
Figure 11. Flywheel schematic.



2.3.1.2 Applications and services

The main advantage of flywheels is their high power density, which is the amount of power (energy transfer over time) per unit volume. The graph in Figure 12 illustrates this power density in comparison to other energy storage technologies (Akhil et al. 2013). As illustrated, flywheels are somewhat comparable to supercapacitors in terms of power density. Another advantage of flywheel storage is its high efficiency. The typical “round-trip” efficiency is 70%–80%. Round-trip efficiency is the ratio of the energy put into the storage system to the energy that can be recouped from the storage system (Boicea 2014). Some flywheel systems now have efficiencies up to around 95% (Luo et al. 2015).

Figure 12. Comparison of storage technologies. (Image reproduced from Akhil et al. 2013. Public domain.)

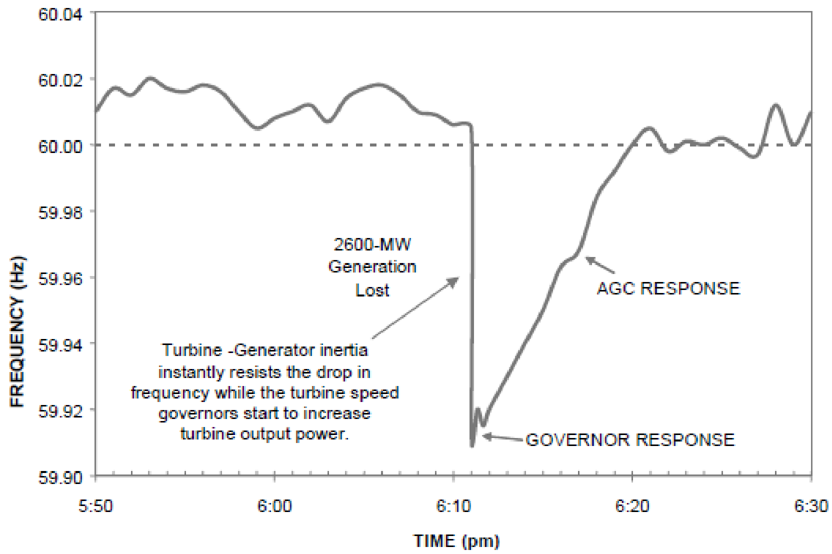


UPS = Uninterrupted power source.
T&D = Transmission and distribution.

The high power density of flywheels makes them useful for power-quality applications. The quick charge and discharge rates of flywheels makes them particularly useful for frequency regulation (Boicea 2014). When power generated does not equal the load, frequency either increases or decreases, which can cause damage to equipment connected to the grid (Kirby et al. 2002). Flywheels can make this change in frequency less drastic until the power output and load have a chance to equalize. Figure 13 graphically illustrates how this works (Kirby et al. 2002).

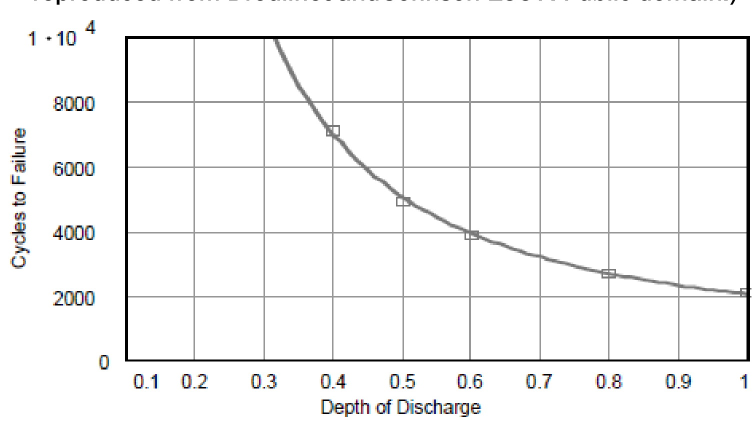
Their quick discharge characteristic also makes them useful as uninterruptible power systems for temporary backup power to critical equipment. They are usually integrated with other higher-volume, less responsive storage systems (Boicea 2014).

Figure 13. Frequency regulation response. (Image reproduced from Kirby et al. 2002. Public domain.)



Flywheels have a relatively long lifetime of approximately 100,000 charge/discharge cycles. Flywheels are also low maintenance and have no depth-of-discharge effects (Boicea 2014). Depth of discharge affects the lifetime of certain batteries. For example, Figure 14 shows how the number of cycles of a Li-ion battery will decrease if it is allowed to discharge to greater depths (Drouilhet and Johnson 1997). Because flywheels are not subject to these effects, one can see how their lifetime will generally be much longer than traditional batteries.

Figure 14. Depth-of-discharge effects on batteries. (Image reproduced from Drouilhet and Johnson 1997. Public domain.)



Flywheels have also been used for transport and distribution services (Boicea 2014) and in the aerospace industry (Luo et al. 2015).

The DoD or Army could implement flywheels in power conditioning applications. For example, flywheel uninterruptible power systems could provide frequency regulation and short-term storage to critical equipment in the event of a power interruption. Potential facilities that could benefit from this include installation hospitals, police and fire stations, communications nodes, and headquarters administrative buildings with high-priority missions.

2.3.1.3 Operating and functional limitations

While flywheels have high *power* density, they have low *energy* density. Energy density is the amount of energy stored per unit volume. Typical flywheels can store 0.5–10 kWh. Median performance is around 2–6 kWh, and there is potential for flywheels to reach 25 kWh upon further development (Boicea 2014). In contrast, typical Li-ion battery storage systems can store energy on the magnitude of megawatt-hours as opposed to kilowatt-hours (Luo et al. 2015). Because of their low energy density, flywheels work best in hybrid renewable energy storage systems, where they can be integrated with batteries, which provide longer-term storage (Boicea 2014).

Coasting efficiency, which is how much power is lost while the system sits charged with no load, is the other major drawback to flywheel storage systems (Boicea 2014). As much as 20% of stored energy can be lost per hour (Luo et al. 2015).

Other design considerations include internal friction and dynamic stability. Modern designs correct for these factors by using low-friction gases, vacuum pumps, magnetic bearings, composite rotors, and cooling systems. The dynamic nature of flywheels also brings up unique safety concerns that are not typical in other storage technologies. Flywheels require some type of device to contain fragmentation in case of failure (Boicea 2014). Even composite flywheels must operate near yield stress to achieve high enough rotational speeds to optimize energy storage, and their failure mechanisms are material dependent. Therefore, containment requirements in case of a failure event vary across designs (vor dem Esche 2016). This concern likely applies in the design of a site-specific flywheel only, rather than the adoption of a commercially available one.

2.3.1.4 Cold regions suitability

Flywheels have proven their ability to perform in cold regions. There are several commercially available flywheels that can perform in harsh environments. Beacon Power's advanced composite flywheel, for example, is rated to −35°C (Beacon Power 2014). Active Power's flywheels are rated to −40°C (Active Power 2021). Alaska Energy Authority's Emerging Energy Technology Fund invested significantly in incorporating flywheels into their grid to enhance power quality (Alaska Center for Energy and Power 2012; Beacon Power and Chugach Electric 2015).

2.3.1.5 Average market cost of flywheels

Referring again to Mongird et al (2019), the average total project cost for a flywheel is $11,520/kWh, putting flywheels at the higher end of energy storage costs compared with other technologies. However, given that flywheels are primarily used for power-quality applications rather than bulk storage, they can still be an economic option in certain applications.

2.3.1.6 Case studies

A case that proves both the longevity and cold-weather performance of flywheels is the Usibelli Coal Mine in Healy, Alaska. The mine installed a dragline in 1978. A dragline is an apparatus that moves heavy materials during mining operations. This created large, fluctuating loads on the mine's power supply, creating a need for power-quality management. In 1982, the mine installed a 36,000 kg flywheel to manage the power fluctuations. The flywheel is still in operation today (Usibelli Cole Mine 1987).

2.3.2 Pumped hydro storage

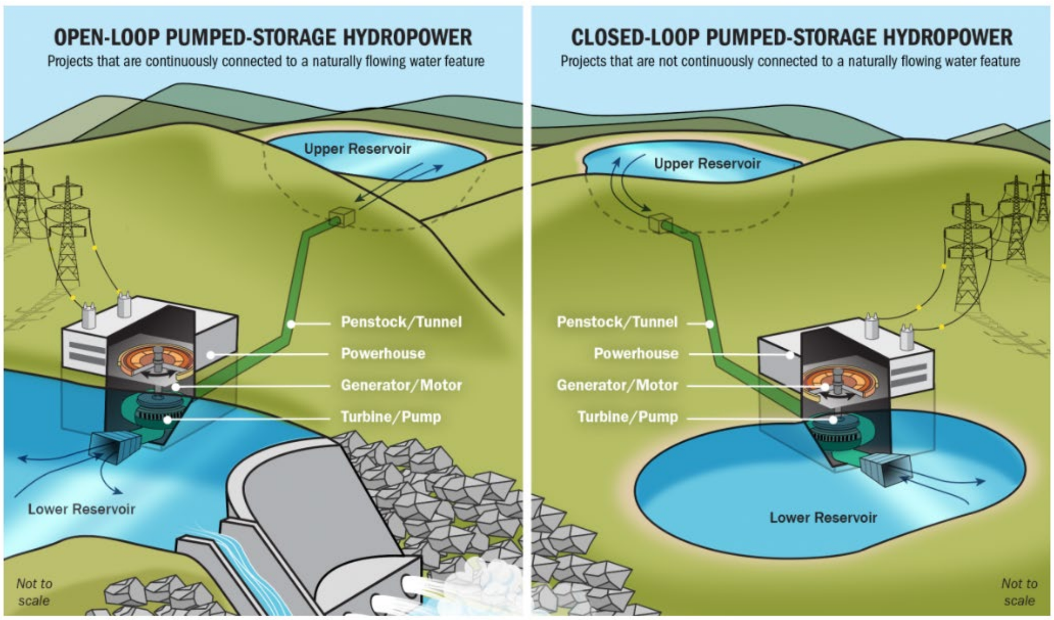
2.3.2.1 Description of technology

Pumped hydro storage takes advantage of the potential energy of elevated water. When energy demand is low, a pump diverts water from a lower elevation storage area to a higher elevation storage area for future use. When there is a greater demand for electricity, the water flows back downward through a hydroturbine, which powers an electrical generator (Boicea 2014).

Dams function in the same way; however, the water is naturally collected at a higher elevation rather than being pumped.

The amount of energy stored (watt-hour) is proportional to the height difference between the two reservoirs and the volume of water stored. The power rating (watts) depends on the water pressure, flow rate, and the specific power ratings of the mechanical components (turbine and generator) (Luo et al. 2015). Figure 15 illustrates pumped hydro storage systems.

Figure 15. Pumped hydro storage illustrations. (Image reproduced from DOE, "Pumped-Storage," n.d. Public domain.)



2.3.2.2 Applications and services

Pumped hydro storage is effective in bulk energy storage applications (Boicea 2014). The United Kingdom, for example, has a national pumped hydro storage capacity of 27.6 GWh (Luo et al. 2015). Individual pumped hydroelectric storage plants' power rating can range anywhere between 1 MW and 3003 MW (Luo et al. 2015).

These systems are normally very efficient (around 80%) in storing a large quantity of energy. However, systems that run the pump and turbine at the same time are not as efficient. Newer designs could solve this by including turbines with guide vanes (grooves that direct water around bends at the correct angle to improve efficiency) and impellers (Boicea 2014).

Pumped hydro storage plants also have a long operational lifetime of around 40 years. Because of their long lifetime and wide use, the technology of pumped hydro storage is well-developed at this point and has a long proven history of performance (Luo et al. 2015).While each system must be designed for the specific site, there is a wide knowledge base from which to draw.

The DoD or Army could implement pumped hydro storage at any facility or installation requiring bulk power storage, given that the appropriate site is selected or available. Sites require elevation head, water availability, and adequate space.

2.3.2.3 Operating and functional limitations

Pumped hydro storage has clear limitations in terms of scalability and versatility. Hydro storage requires a great deal of real estate and can be applied realistically only in places where there is a large available water supply. As mentioned above, the United Kingdom has a large pumped hydroelectric storage capacity, but the country is very limited in terms of future hydro storage expansion due to site requirements (Luo et al. 2015).

The magnitude of pumped hydro storage plants also means that there is a high initial cost and significant construction time. The more recent popularization of using less traditional sites, such as oceans, old mine shafts, and underground caves as reservoirs (Luo et al. 2015), can expand available useable sites and offset initial construction costs.

2.3.2.4 Cold regions suitability

Hydropower is a large source of energy in many arctic climates. However, when installed in cold climates, ice can be the cause of safety issues and damage to the system. These issues can affect the daily operation of the plant during the winter, when energy demands are highest. Designers have implemented various coping strategies to overcome these issues, including design guidelines, operational guidelines, structural ice control (e.g., levees to prevent flooding, bank protection against scour, and dams to encourage ice cover and reduce open-water area), and thermal measures (e.g., heating of gates and trash racks, covering intakes to reduce radiation losses, using bubblers to raise warm water to the surface, or directing thermal effluents) (Gebre et al. 2013).

2.3.2.5 Average market cost of pumped hydro storage

Mongrid et al. (2019) reports that the average total project cost for pumped hydro storage is $165/kWh, making it one of the most economical energy storage options, second only to compressed-air energy storage (CAES) in total project costs per kilowatt-hour.

2.3.2.6 Case studies

In Norway, hydropower accounts for 99% of its energy production. This illustrates that hydro storage and hydropower can be a reliable and effective power source in cold regions despite complications due to ice formation during winter months. Ice formation is complex, and small changes in system design or flow regulation can have compounding effects. Even in Norway, the effects of ice on their systems are not well-documented and researched. This makes the development of advanced ice-mitigation measures difficult since there is a limited body of existing knowledge (Gebre et al. 2013).

2.3.3 Advanced Rail Energy Storage

2.3.3.1 Description of technology

A new and developing technology by Advanced Rail Energy Storage (ARES) North America makes use of potential energy much like pumped hydro storage. In contrast, ARES harnesses the weight of elevated rail cars as opposed to water. Upon being released from a higher elevation, the rail cars generate power through their regenerative braking system (McFadden 2017).

2.3.3.2 Applications and services

The ARES technology could be an alternative bulk energy storage system to pumped hydro storage. ARES North America's pilot project in Tehachapi, California, operates at 78%–80% efficiency, has a design lifetime of 40 years, and has 100% coasting efficiency. Their planned project in Nevada will be capable of delivering 50 MW of power and 12.5 MWh of capacity. This project will require a 9.3 km rail line and 707,604 kg in weighted rail cars (Ruoso et al. 2019).

The DoD or Army could implement the ARES technology at any facility or installation requiring bulk power storage, given that the appropriate site is selected or available.

2.3.3.3 Operating and functional limitations

While the ARES system has the benefit of eliminating the need for water in pumped hydro storage, it is still necessary to have a fairly large site as it requires a sufficient elevation change over a long distance to function.

2.3.3.4 Cold regions suitability

This is still a new technology and, therefore, has not been researched in cold regions. Both the existing and planned projects are in the southwest region of the United States (McFadden 2017). The project team assumes that this storage technology would encounter the same limitations as typical rail systems in the cold.

2.3.3.5 Average market cost of Advanced Rail Energy Storage

The estimated project cost for the planned Nevada ARES system is $55 million (McFadden 2017). Given the newness of this system, an in-depth economic analysis is not available.

2.3.3.6 Case studies

No further case studies exist aside from the California pilot project and the planned Nevada project.

2.3.4 Gravity power module

2.3.4.1 Description of technology

Another new technology worth mentioning is the gravity power module (GPM). It again, like pumped hydro storage and the ARES technology, harnesses gravitational potential energy. GPM is essentially a giant piston contained in a deep, water-filled excavation. The piston is equipped with moving seals to prevent leakage during cycling. When electricity demand is low, grid electricity moves the piston to ground level. When demand is high, the piston drops, forcing water through the return pipe and pump-turbine at ground level to power a generator (Galant et al. 2013).

2.3.4.2 Applications and services

GPMs have the potential to store hundreds of megawatt-hours in a small footprint, which makes it an option in areas that are more densely populated (Galant et al. 2013). This also makes it one of the more power-dense storage systems (Ruoso et al. 2019). A group of GPMs could also be installed to achieve higher storage capacity. Galant et al. (2013) estimate the response time of GPMs to be less than 20 seconds, going from black start to full power. GPMs also have high efficiency at around 75%–80%, high coasting efficiency, and a long expected lifetime of more than 30 years (Ruoso et al. 2019).

2.3.4.3 Operating and functional limitations

While the site requirements of pumped hydro storage or the ARES system are largely reduced using the GPM method, it is still not a “plug and play” storage system. It requires a decent engineering and construction effort. As it is a new technology, it has not been widely studied.

2.3.4.4 Cold regions suitability

Gravity Energy AG, the company who developed GPM, currently has their research and development project under construction in Northern Germany (Gravity Energy AG, n.d.). No other cold regions information was found in the literature.

2.3.4.5 Average market cost of gravity power modules

Ruoso et al. (2019) reported that the levelized costs of energy storage of GPM and pumped hydro storage were comparable. When GPM is fully mature, it will reportedly have a capital cost equal to or slightly higher than pumped hydro storage (Ruoso et al. 2019). This makes it an attractive alternative as it offers many of the same benefits as pumped hydro storage but is also modular in nature, which results in a relatively short construction time, easier permitting, use of conventional mine excavation techniques, and automated construction procedures. Additionally, it requires less excavation than pumped hydro storage per storage capacity. All of these factors make GPM construction relatively affordable (Galant et al. 2013).

2.3.4.6 Case studies

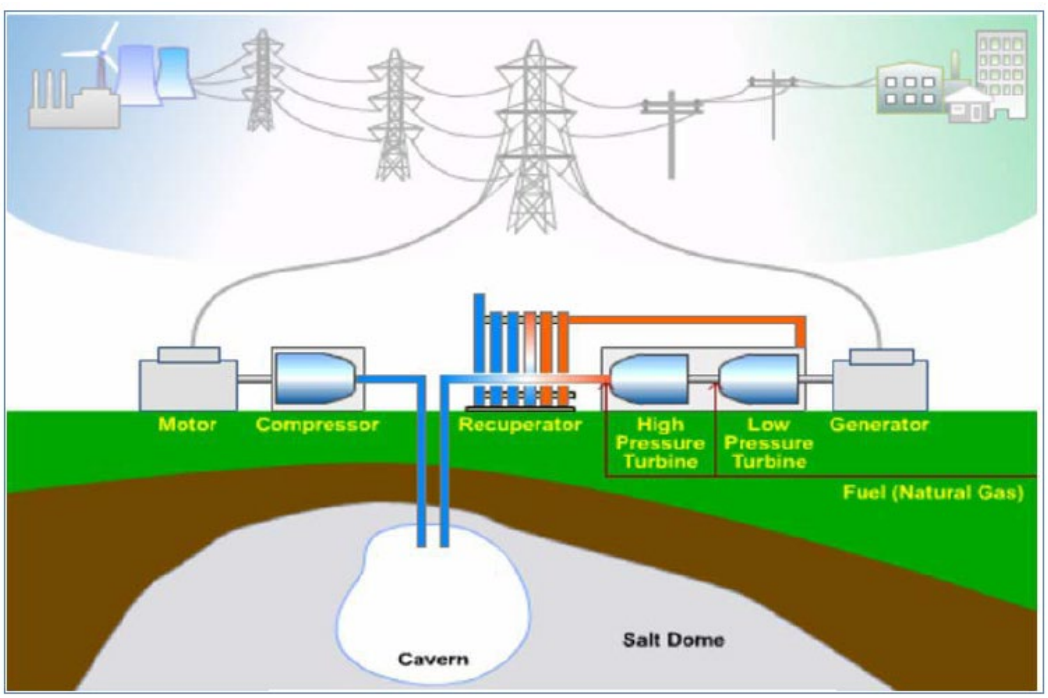
According the Gravity Energy AG's website, their pilot project is underway in Lübeck, Bavaria, Germany. Core drilling is complete, and the geotechnical analysis and system seal testing are underway. Once the remainder of the design is complete, it will go to contractors for bid. The resulting GPM will have a 1 MW capacity (Gravity Energy AG, n.d.).

2.3.5 Compressed-air energy storage

2.3.5.1 Description of technology

Like with pumped hydro storage and the ARES system, CAES uses the grid in periods of low demand to build up stored energy. The air is compressed into an above- or below-ground reservoir; and then when demand is high, it is heated and expanded through a gas turbogenerator to create electricity (Boicea 2014). The schematic in Figure 16 illustrates the complete system (Akhil et al. 2013). Waste heat from the compression process and from the turbine exhaust can be recovered by a recuperator and used to heat the air when it is expanded to make the system more efficient (Luo et al. 2015).

Figure 16. CAES Schematic. (Image reproduced from Akhil et al. 2013. Public domain.)



Advanced adiabatic CAES use a thermal storage system in conjunction with the traditional CAES to eliminate the need for fuel combustion in expanding the air (Luo et al. 2015).

2.3.5.2 Applications and services

CAES is primarily used for utility-scale bulk power storage. CAES can achieve power ratings in the hundreds of megawatts for periods of many hours (Boicea 2014; Luo et al. 2015). The technology can also be used for backup power and power-quality applications, such as frequency and voltage control, as they have moderate response times and work well under partial load (Luo et al. 2015). When something works well under partial load, it means that its efficiency does not drop significantly in comparison to when the full electrical load is being drawn from the system (Ebrahimi and Keshavarz 2015). Existing CAES applications have demonstrated 91%–99% starting and running reliabilities (Luo et al. 2015). All existing CAES are large, underground facilities.

Researchers such as Proczka et al. (2013) are investigating smaller-scale, above-ground CAES, but achieving higher efficiency is more challenging. Above-ground CAES stores the compressed air in large tanks. These systems are generally used for uninterrupted power sources or backup power applications. Proczka et al. (2013) published recommendations for efficient design of small CAES systems.

2.3.5.3 Operating and functional limitations

Currently, there are only a few examples of large-scale CAES in existence. Since CAES systems are not yet widely used, there are limited design recommendations and lessons learned to pull from the base of knowledge (Boicea 2014). Existing CAES plants have efficiencies ranging from around 42% to 54% (Luo et al. 2015). This is not great in comparison to other storage technologies. According to Boicea (2014), in the future, CAES should be able to achieve 71% efficiency with system improvements.

Other limitations of CAES systems are their size and specific site requirements. The caverns must be large (hundreds of thousands of cubic meters) and located at great depths (hundreds of meters) to achieve an appropriate storage capacity and pressure head (Boicea 2014). Site selection can be challenging. If naturally occurring geologic voids are used (such as salt caverns), they must be of suitable strength and stability to support a CAES system (Luo et al. 2015).

The DoD or Army could implement CAES at any facility or installation requiring bulk power storage, given an appropriate and available site. Both underground and above-ground CAES require significant space; and underground CAES requires unique, naturally occurring underground voids or an exceptionally engineered underground cavern.

2.3.5.4 Cold regions suitability

Since there are not many existing CAES systems in operation, the performance of CAES in cold regions does not appear to be well-documented. There are, however, a few examples demonstrating that they are capable of being deployed in cold regions. The oldest plant, described in section 2.3.5.6, was built in Huntorf, Germany, and is still in operation today (Boicea 2014). The average low in Germany in January is −2.9°C (The Weather Channel 2020a). Additionally, Hydrostor is a Canada-based CAES company that has built two CAES systems in Goderich and Toronto (Hydrostor 2020). The average low in Toronto in January is −11.1°C (The Weather Channel 2020b).

2.3.5.5 Average market cost of compressed-air energy storage

Mongird et al. (2019) reported CAES as having the lowest average project cost per kilowatt-hour out of all the systems covered in the report: $105/kWh.

2.3.5.6 Case studies

The oldest existing grid-scale CAES plant, in Huntorf, Germany, can provide 290 MW over 2 hours. To achieve this, it requires two caverns, one 140,000 m^3 and the other 170,000 m^3. The caverns are also at 650 m below grade to maintain a pressure of 100–7000 kilopascals (Boicea 2014). It also requires 0.8 kWh base-load electricity and 1.6 kWh of gas to produce 1 kWh of stored energy. This means it has an approximate 42% efficiency (Boicea 2014).

The only large-scale CAES system in the United States is in McIntosh, Alabama. It was built in 1991 and uses preexisting salt caverns to store the compressed air (Luo et al. 2015). To illustrate the potential capacity of these systems, the McIntosh plant can operate at 100% capacity (110 MW) for 26 hours and provides power to 11,000 homes (Kirby et al. 2002). It has an underground depth of 457 m to achieve its power rating (Boicea 2014). This plant was able to improve its efficiency to around 54% by using a recuperator. Recuperators recycle system waste heat by storing it and reusing it to help power the combustion of the air upon expansion (Luo et al. 2015)

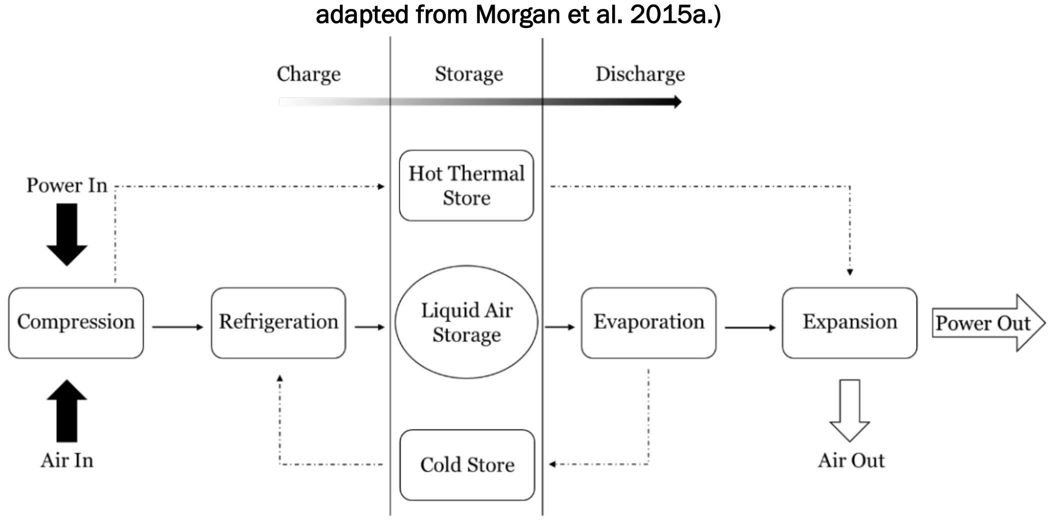
2.4 Thermal

2.4.1 Liquid-air energy storage

2.4.1.1 Description of technology

Liquid-air energy storage (LAES) operates in three distinct phases of charging, storage, and discharging. The system is charged using excess energy to drive a refrigeration unit to cool air at –196°C, the temperature at which atmospheric air changes from a gas to liquid at atmospheric pressure. Liquid air is 1/700 the volume of gaseous air and can be stored in well-insulated storage vessels (e.g., austenitic stainless steel or invar tanks). When power is needed, the system discharges by drawing the liquid air from the storage tank and transferring it through heat exchangers where it is pressurized (Figure 17). The pressurized air is expanded through a gas turbine to generate electricity (Morgan et al. 2015a, 2015b; Raj 2020).

Figure 17. Liquid-air energy storage system process diagram. (Image adapted from Morgan et al. 2015a.)



Although large-scale LAES is a nascent technology, its system components are widely available, mature technologies. The system can be charged using air liquefiers from the cryogen industry; the liquid air can be stored in cryogenic storage tanks used for liquid N_2, O_2, liquid natural gas; and gas turbines are available from the power industry. These system components are relatively inexpensive and have more than 30 year longevity, reducing the capital and maintenance cost for start-up (Morgan et al. 2015a; Legrand et al. 2019; Raj 2020).

Additional advantages of LAES are that, unlike batteries, it does not require toxic or rare resources, reducing its environmental impact and production cost. Unlike pumped hydrogen technology, it is not dependent on geographical location, allowing for site selection and proximity to installations.

2.4.1.2 Applications and services

Surplus electricity from renewables or nuclear during high volume hours is used to make liquid air for storage. This can be used to supplement power requirements when electrical generation is low. It could also be used for load shifting (Y. Li et al. 2014), and it may be more economically feasible than Li-ion batteries (Dockter et al. 2017). However, most research focuses on its use in generating continuity in renewable energy supply (Morgan et al. 2015a; Legrand et al. 2019).

Electricity supply that is not reliable or that is vulnerable to attack reduces the security of a military installation. This increases the need for self-sustaining isolated power generation (e.g., renewables). However, given the intermittent nature of some renewables, they require an energy storage system to create continuity in the energy supply. LAES plants can store and supply energy for a full day; they have a small footprint relative to other technology, such as pumped hydrogen; and operational costs are projected to decrease over the next decade (Morgan et al. 2015b). The scalability of this technology from the kilowatt to megawatt and its potential to isolate an installation from grid power (e.g., in conjunction with renewable energy sources) make it a promising technology for Army and DoD installations, including in remote regions.

2.4.1.3 Operating and functional limitations

A major limitation to LAES is its low round-trip efficiency (i.e., the ratio of energy required to make LAES to the amount of energy recovery from storage). For Highview Power's pilot plant developed for the University of Birmingham's Centre for Cryogenic Energy Storage (Highview Power, n.d.), researchers modeled the theoretical round-trip efficiency to be 65%; however, the actual measured round-trip efficiency over a 12-hour period was 8% (Morgan et al. 2015b). The discrepancy was attributed to the small scale of the LAES plant and its inability to recycle cold and heat from the system to optimize efficiencies (Morgan et al. 2015b).

Other theoretical models put the efficiency of a large-scale LAES plant around 21.6% round trip without thermal recycling and between 50% and 60% with optimized thermal recycling (Morgan et al. 2015b; Sciacovelli et al. 2017; Tholander and Högberg 2018; Krawczyk et al. 2018). This remains a low round-trip efficiency relative to battery storage technology with 70%–90% efficiencies (De Leon et al. 2006; Luo et al. 2015) and pumped hydrogen energy storage with 70%–85% efficiencies (Mahlia et al. 2014). However, it is an acceptable range to provide energy storage to create continuity of supplied energy for systems relying on intermittent renewables.

Currently, LAES systems are capable of storing energy for weeks at a time (Highview Power, n.d.). Large-scale plants capable of 50 MW and 400 MWh of storage can generate up to 8 hours of energy for power supply (Danigelis 2019).

2.4.1.4 Cold regions suitability

In cold regions with shorter winter days and longer nights, often greater than 12 hours, the feasibility of LAES to provide energy supply continuity for PV systems depends heavily on the storage capacity of the system and the load of the service region or installation. Currently, the largest project LAES facility has a storage capacity of 400 MWh (Danigelis 2019); this could provide 33 MW max output for 12 hours. However, if the energy was supplied from multiple sources (e.g., solar and wind) to supplement storage, LAES may be able to service a larger load and a longer time interval.

LAES technology is still in the developmental phase, and there has been little research on performance in cold regions. Given its thermal requirements for low temperatures during charging and storage and its use of waste heat during discharge, further investigation into LAES applications is needed before a large-scale application of this technology in cold regions.

2.4.1.5 Average market cost of liquid-air energy storage

The levelized cost of storage (LCOS) is defined as the total investment cost of an energy storage technology over its lifetime divided by the cumulative energy delivered (Pawel 2014; Schmidt et al. 2019). LCOS is comparable to the levelized cost of energy (LCOE), which is used to measure energy generation technologies, and allows for comparison across different storage technologies. The LCOS for LAES is \$90–\$250/MWh (Brett and Barnett 2014; Legrand et al. 2019). This cost depends heavily on the round-trip efficiency of the technology (Legrand et al. 2019; Xie et al. 2019) and is expected to decrease as the technology advances (Xie et al. 2019).

2.4.1.6 Case studies

The first pilot-scale LAES facility began operation in 2010, developed by Highview Power Storage for the University of Birmingham Centre for Cryogenic Energy Storage (Brett and Barnett 2014; Sciacovelli et al. 2017; Xie et al. 2019). The plant is capable of 300 kW peak output and can store 2.5 MWh of energy (Morgan et al. 2015b; Highview Power, n.d.).

In 2018, a grid-scale demonstrator plant opened in the Pilsworth Landfill facility in Manchester, United Kingdom (Figure 18). This plant can generate 5 MW of peak supply and 15 MWh of storage (3 hours of maximum power output if fully charged) (Xie et al. 2019; Highview Power, n.d.). In 2019, Highview Power Storage released their plans to build a 50 MW/400 MWh (8 hours of storage at max output) LAES plant in northern Vermont that will be interconnected with the grid (Business Wire 2019).

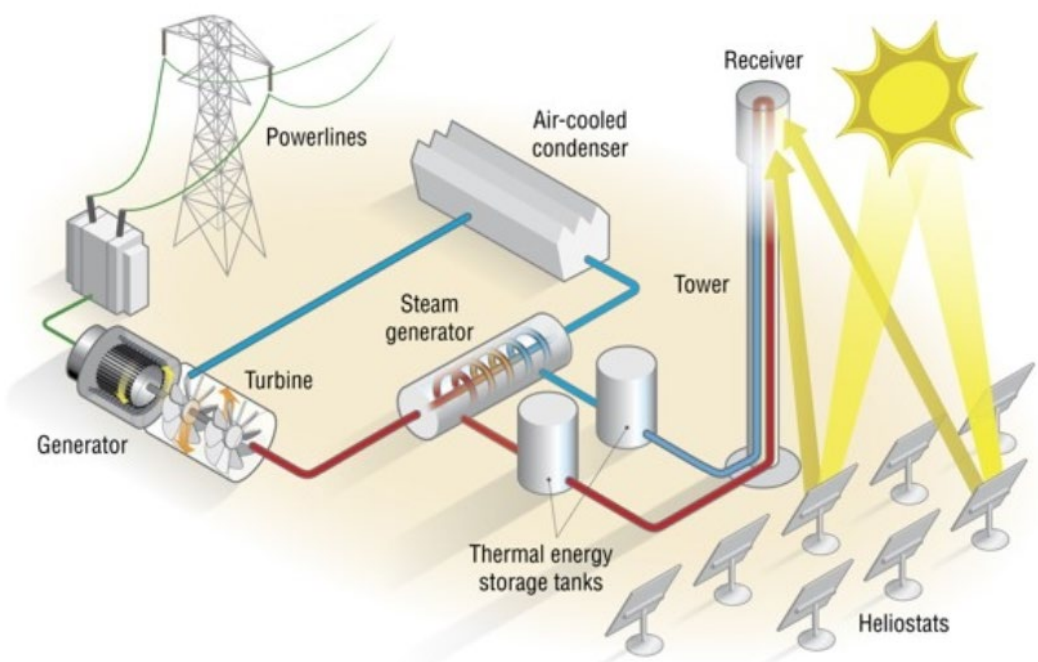
Figure 18. Pilsworth grid-scale demonstrator plant in Manchester, United Kingdom. (Image reprinted with permission from Highview Power, n.d.)

2.4.2 Thermal energy in heat-transfer fluids

2.4.2.1 Description of technology

Heat-transfer fluids (HTFs) are generally used as energy storage mediums for concentrated solar power (CSP) plants. CSP plants use mirrors or lenses to focus solar energy from a larger area to a small receiver (Figure 19). To maximize the amount of solar energy collected, the mirrors and lenses of the CSP track and follow the movement of the sun. For smaller-scale applications, the receiver is integrated with a parabolic trough, enclosed troughs, or Fresnel plants (Al-Juboori and Al-Shawwreh 2018). For larger-scale applications where the receiver is stand-alone, such as a solar tower, CSP plants have shown the most promise for grid-scale applications compared to other systems (Reilly and Kolb 2001; Alnaimat and Rashid 2019; Bielecki et al. 2019). At the receiver, the solar energy is either used to create steam to drive a turbine for energy generation or stored as specific heat in a transfer medium to generate energy at a later time. Energy storage allows for smooth power output as well as continuity in energy supply when solar energy is not available (e.g., overnight) (Bielecki et al. 2019).

Figure 19. Diagram of a functional schematic for a CSP plant. (Image reproduced from DOE 2014. Public domain.)



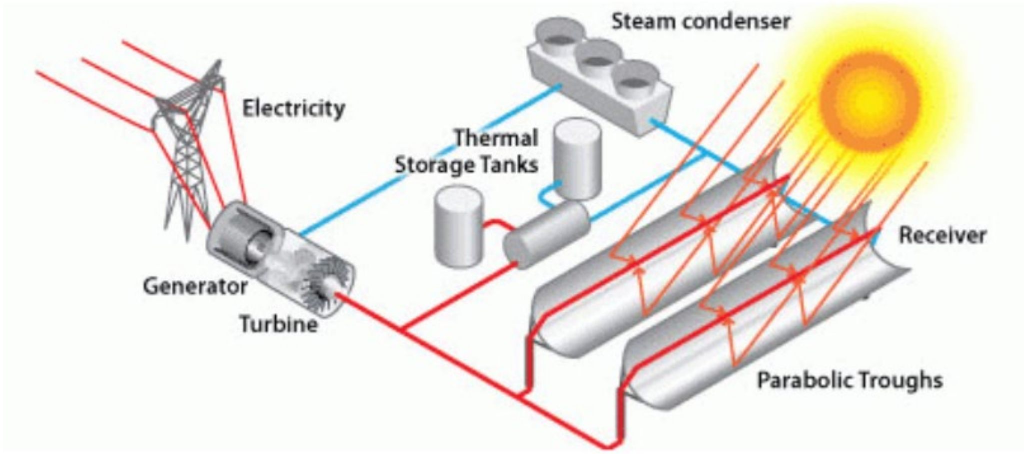
In the 1990s, Sandia National Laboratory developed technology that utilized molten salt as the heat-transfer medium (Reilly and Kolb 2001). Molten-salt energy storage involves storing liquid salt at 288°C in a "cold" tank. The liquid salt is passed through a solar collector where is it heated to about 550°C and transferred to a "hot" tank where it can be stored for up to a week. To generate electricity, the hot molten salt is used to produce superheated steam that drives a turbine generator. Molten salt has been the preferred heat-transfer medium for large-scale applications given its greater economic value relative to other heat-transfer fluids, such as mineral and synthetic oils (Herrmann et al. 2004; Al-Juboori and Al-Shawwreh 2018; Fritsch et al. 2019).

2.4.2.2 Applications and services

Concentrated solar plants that utilize molten salt as heat-storage fluids have a high energy storage capacity ranging from megawatt-hours to gigawatt-hours (Figure 20; Reilly and Kolb 2001; Pacheco et al. 2013). At this magnitude, they can feed into the power grid. These systems are also very flexible given their rapid charge and discharge rates (Pacheco et al. 2013), allowing for quick response to changing environmental conditions. They are not restricted by regional geographic features and can be installed in locations with high sun exposure.

Concentrated solar to molten salt storage can be scaled down to kilowatt production, reducing the overall size of the generation plant (Seshie et al. 2018). In this power-generation range, many installations utilize parabolic troughs that can be as small as a few square meters to concentrate solar energy to a heat-transfer fluid. This application has shown promise in rural communities with limited access to grid power (Seshie et al. 2018). With the potential to island energy supply and storage, DoD and the Army could benefit from this technology at remote installations or installations in a foreign territory where unreliable grid power may create vulnerabilities during combat. Utilizing CSP to heat-transfer fluids could minimize this vulnerability and could reduce long-term costs of energy. At installations with reliable grid power, DoD and the Army could use this technology for peak saving to reduce utility costs and have it available for backup energy supply and storage.

Figure 20. Theoretical schematic of parabolic troughs to concentrate solar energy to a heat-transfer fluid for energy storage. (Image reproduced from DOE, "Linear," n.d. Public domain.)



2.4.2.3 Operating and functional limitations

Large-scale CSP plants that use molten salt energy storage have a large footprint, and solar fields can cover 6.5 km^2 (Power Technologies 2021); however, smaller-scale applications may be feasible for the kilowatt supply range. They are limited to regions that receive a large amount of direct solar energy. Molten salt is a mixture of 60 wt% sodium nitrate ($NaNO_3$) and 40 wt% potassium nitrate (KNO_3), making it susceptible to decomposition at high temperatures, limiting its heating capacity to 550°C and its ability to store thermal energy (Alnaimat and Rashid 2019). There have been successful efforts to increase its heat-storage capacity using additives, such as copper oxide (CuO) nanoparticles (Awad et al. 2018).

2.4.2.4 Cold regions suitability

Thermal energy storage systems in concentrated solar plants, to date, have been installed in temperate regions. Investigative research on their applications in cold regions is limited. Molten salt can store specific heat for up to a week and may have limited applications in cold regions with reduced winter sunlight, requiring seasonal energy storage options. Additionally, maintaining high temperatures in molten salt may require heavily insulated storage systems. This technology has been proposed as an inexpensive alternative to indoor heating that requires electricity (Turrini et al. 2018). DoD and the Army could benefit from this application in cold regions to reduce heat costs and power consumption. Reducing the need to use electricity for heating would conserve energy during times of disruption, increasing the energy resiliency of an installation. However, further research is required to address the cold region suitability of this technology.

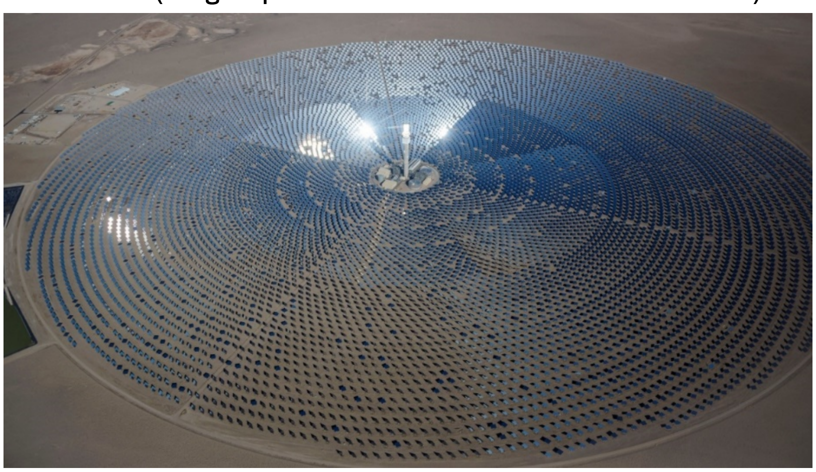
2.4.2.5 Average market cost of molten salt energy storage

The LCOE for a concentrated solar plant that utilizes molten salt as the thermal energy storage medium ranges from $125 to$175/MWh (NREL 2018). This is competitive with other energy storage technologies.

2.4.2.6 Case studies

In 2015, Tonopah Solar Energy began operation at their Crescent Dunes Solar Power Plant near Tonopah, Nevada (Figure 21). The plant has a 110 MW capacity and uses molten salt to store energy for a max discharge of 10 hours. This supplies energy to approximately 75,000 households (Power Technologies 2021).

Figure 21. Crescent Dunes 110 MW concentrated solar plant in Tonopah, Nevada. (Image reproduced from Shultz 2017. Public domain.)



The Gemasolar Thermosolar Plant began operation in 2011 in Sevilla, Spain. It is a concentrated solar plant with a 19.9 MW capacity and uses molten salt thermal storage that can supply 15 hours output when sunlight is not available. The heliostat array spans 304,750 m^2, and the power tower is 140 m tall (NREL 2017).

2.4.3 Additional thermal energy storage technologies

The following are additional thermal energy storage technologies that do not currently have an application for DoD or Army installations in cold regions.

2.4.3.1 Phase-change materials

Phase-change materials (PCM) absorb or release latent energy during a phase transition. The amount of energy, and whether energy is absorbed or released, depends on the heat of fusion for a given PCM. When a PCM transitions from a liquid to a solid, it can give off energy in the form of heat. For example, a supersaturated solution of sodium acetate can exist as a liquid at room temperature; but once the sodium acetate begins to form crystals, heat is given off. PCMs have shown potential as a thermal storage medium for concentrated solar plants; however, they have not achieved commercial level or large-scale application due to prolonged charging and discharging caused by low thermal conductivity (Mofijur et al. 2019). The project team does not currently consider PCMs a potential energy storage technology for Army and DoD applications in cold regions given their slower response time and limited market availability. However, research is ongoing, and future reviews should revisit this technology.

PCMs have shown the most promise as an insulating material to reduce energy consumption (Kosny et al. 2013). When a room begins to cool, the PCM begins to solidify or crystallize, giving off heat, helping to regulate the temperature inside of the facility. As the room heats up and the PCM begins to change back into a liquid, it stores the latent thermal energy, which can be released again as the room cools and the PCM recrystallizes (Kosny et al. 2013). Incorporating PCMs into building materials in cold regions can help when the electricity for heating a cold region facility is provided by a renewable resource like wind or solar. During times when that renewable energy is available, the building can be heated, and excess latent heat can be stored in the PCM. Then, during periods when that energy is not available, the PCM can help regulate the temperature by releasing the stored heat back into the facility. Although there is merit in this technology for Army and DoD applications to conserve energy, the use of PCM as building materials was beyond the scope of this review and not thoroughly investigated.

The use of microencapsulated phase-change materials (MPCM) in slurries with HTFs has shown better heat-carrying capacity than conventional

HTFs in laboratory settings (Alvarado et al. 2007). Increasing the heat-carrying capacity of an HTF would reduce flow rates during transport of fluid from heat source to the designated space for heat transfer, potentially reducing system operation costs. Morefield and Alvarado (2015) investigated the feasibility and cost-reduction potential of MPCM at Fort Hood, Texas, and Fort Dodge, Iowa. They found that the MPCM increased heat-transfer performance by 10% compared to conventional HTF, resulting in a 3% reduction in system power consumption. However, they determined that, at the time of their report, the technology was not mature enough for widespread applications at DoD installations.

2.4.3.2 Solar pond

Solar pond energy storage involves saltwater in a large “pond” that is heated with thermal energy. Warmer water concentrates at the bottom where it is saltiest and is trapped by the cooler, less salty water above (Valderrama et al. 2011). The heated water is moved through heat exchangers to heat spaces or to generate electricity via thermoelectric devices or organic Rankine cycle engines. The project team does not currently view solar pond technology as a promising energy storage system for Army and DoD applications in cold regions because it is geographically limited due to its size and may not be feasible for a cold region where ponds may require additional heat to stop ice formation.

2.4.3.3 Heat storage in packed beds

Thermal energy can be stored in packed beds, which are beds of loosely packed materials such as rock, concrete, ceramics, or pebbles. Air is circulated through the packed bed to transfer specific heat, which can be used to supply heat to a building or in a power cycle to generate electricity (Anderson et al. 2015; Sarbu and Sebarchievici 2018). Packed-bed energy storage has been widely investigated for feasibility (Anderson et al. 2015; McTigue et al. 2018), but its commercial application is still unclear. The project team does not currently view heat storage in packed bed as a promising energy storage technology for Army and DoD application in cold regions given the limited research and case studies.

2.4.3.4 Steam accumulator

Steam accumulators use energy to make steam in secondary containment. An insulated steel pressure tank is half filled with cold water, and steam is blown in from a boiler through a perforated pipe under the water. The steam heats the water and pressurizes the space above. When the accumulator is fully charged, the water level will have risen to three-quarters full, increasing the temperature and pressure. Steam can be drawn off to power a steam turbine for energy generation. As steam is released, the pressure reduces in the tank, causing the water to boil and generate additional steam. This continues for some time before it has to be recharged (Sun et al. 2017). Steam accumulators are not currently viewed as a promising energy storage system for Army and DoD applications in cold regions because they have not been tested on a large scale and may have limitations in cold regions where water will freeze if not heated and stored properly.

2.5 Electromagnetic

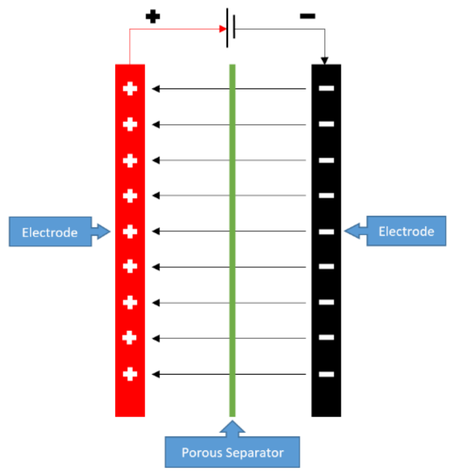
2.5.1 Ultracapacitor

2.5.1.1 Description of technology

Ultracapacitors are essentially high-capacitance capacitors. They produce a charge by moving electrons between the two electrodes. Charge separation creates a voltage potential between two electrodes, which means the electrons move towards the positive electrode (cathode) during charging. Electricity is then discharged to the connected load, and the electrons move back to the negative electrode (anode). These electrodes are separated by a porous-carbon separator, which keeps the electrodes apart but allows the electrons to pass through (Electronics Tutorials 2021). The layers are then coiled together to increase capacity. The closer the electrodes are, the higher the capacitance, which means the best results are achieved by reducing plate separation to a few angstroms. Capacitance can also be increased by using high-surface-area carbon electrodes, which increases the plate-specific surface area (Hall and Bain 2008). Figure 22 shows a schematic of an ultracapacitor.

Ultracapacitors utilize a similar process to batteries; however, the main difference between batteries and ultracapacitors is the power and energy densities of each technology. Batteries are a high-*energy*-density storage technology, which means they have the ability to store more energy for a given weight and volume. Ultracapacitors are a high-*power*-density storage technology, which means they can charge and discharged very quickly (Supercaptech.com 2020).

Figure 22. Ultracapacitor schematic.



It is possible for ultracapacitors to exhibit very high storage efficiencies (>95%), and they can be cycled hundreds of thousands of times without appreciable loss of capacity (Hall and Bain 2008).

2.5.1.2 Applications and services

Ultracapacitors have a wide range of uses. Current applications include portable electronics and transportation. This technology can be used in cars, buses, trains, and other vehicles for regenerative braking, burst power, and reliable start when batteries no longer function.

They have applications in renewable energy systems, also. As more solar and wind generation systems are interconnected, energy storage systems must respond faster and cycle more frequently to ensure grid power quality and resiliency in a generation nameplate mix that includes growing amounts of utility-scale wind and solar. Ultracapacitor-based grid energy solutions are able to respond to high energy demands very quickly and have advanced utility grade control and communication systems (Maxwell Technologies 2021). Ultracapacitors can be used in blade pitch systems for wind energy and provide energy storage for firming the output of renewable installations (Maxwell Technologies 2014).

Potentially, ultracapacitors could be used by Army and DoD facilities for reliable vehicle start in extreme temperatures, due to the technology's ability to operate in a wider range of temperatures than traditional batteries. Reliable and resilient vehicle start is especially necessary for response timing and mission success, especially in emergencies.

2.5.1.3 Operating and functional limitations

One of the main limiting factors for implementing ultracapacitor-only systems in large-scale energy storage is the technology's low energy density. Since ultracapacitors charge and discharge so quickly, they are not suitable for supplying electrical energy for a sustained period of time. However, they do have value in conjunction with large-scale battery systems to compensate for momentary and temporary interruptions. Utilizing ultracapacitors for this allows the ultracapacitors to take the intermittent loading and then distribute a steady supply to the batteries, which would prolong the lifetime of the batteries (Smith and Sen 2008).

2.5.1.4 Cold regions suitability

The main use for ultracapacitors in cold regions is for reliable crank of vehicles in extreme cold conditions. Current commercial off-the-shelf batteries are typically rated down to only −20°C, and that can prevent the batteries from supplying the starter with enough energy to crank the motor (Battery University 2017). In addition, starting the motor puts a significant amount of stress on the batteries, which will degrade them over time, shortening their useful lives. Ultracapacitors are rated for lower temperatures (−40°C) and can be cycled many more times than batteries (Maxwell Technologies 2014). They can be connected directly to the starter motor, bypassing the vehicle's batteries, meaning only the ultracapacitor is exposed to the load and stress of starting the motor. This process more reliably starts the vehicle and lengthens the life of the vehicle's batteries.

2.5.1.5 Average market cost of ultracapacitors

The cost of using the ultracapacitor technology depends on the size of the technology. For vehicle application, a 380 Farad Maxwell ultracapacitor costs $12.23 (Mouser Electronics, n.d.), while the 12 V Maxwell ultracapacitor engine starting module costs $825.00 (Amazon, n.d.). To implement this technology into an energy storage system, it would need to be stacked to scale up to the desired size. Ultracapacitor cells are combined into a series string and assembled into modules. The modules are then installed in a rack system combined with a communications gateway. The racks can then be stacked together to the desired capacity for a large-scale energy storage system (Maxwell Technologies 2021). According to Mongird et al. (2019), an ultracapacitor system has an average total project cost of $74,480/kWh.

2.5.1.6 Case studies

Many commercial trucking companies have implemented the 12 or 24 V Maxwell engine start module for both medium-duty and heavy-duty trucks, shown in Figure 23. The ultracapacitor-integrated start module provides a higher level of reliability and confidence in engine starting with no jump-starts or battery replacements, allowing them to continue to work on schedule. Increased auxiliary loads on trucks from accessories and sleeper cabs, anti-idle regulations, and reduced battery performance in cold weather are just some of the challenges pushing the development of alternative engine-start or battery technology (Maxwell Technologies 2016).

Figure 23. Maxwell Technologies heavy-duty 24V ultracapacitor engine start module.

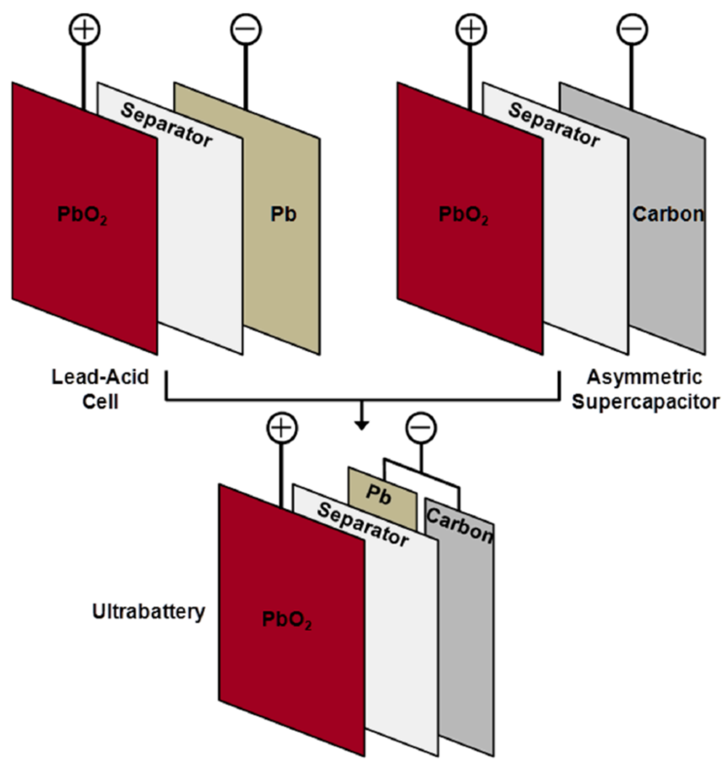
There also are several large-scale grid applications of ultracapacitors. Ultracapacitors were used by the Southeastern Pennsylvania Transportation Authority Light Rail System to recover braking energy otherwise lost as waste heat, which lowers the electricity cost. Yangshan Deep Water Port also used ultracapacitors to mitigate voltage sag caused by the port's many cranes. This prevented the need to install a costly, large transmission line and saved money due to improved efficiency and reduced maintenance. In addition, the California Energy Commission used an ultracapacitor energy storage system to fill in short-term solar power intermittencies and provide ramp rate control for longer intervals. This stabilized solar output and allowed the system to deliver other power-reliability and power-quality services (Maxwell Technologies 2021).

2.5.2 UltraBattery

2.5.2.1 Description of technology

The UltraBattery technology is a hybrid lead-acid battery and ultracapacitor. It was developed by Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) and exhibits higher energy efficiencies, a longer lifetime, and superior charge acceptance under partial-state-of-charge conditions (Ward 2011). Figure 24 shows the schematic diagram of the UltraBattery system. The top of the figure shows the typical schemes for a lead-acid battery on the left and a supercapacitor on the right and how those are combined to form the UltraBattery system at the bottom of the figure.

Figure 24. Schematic diagram showing the configuration of the UltraBattery. (Image reproduced from Enos 2014. Public domain.)



2.5.2.2 Applications and services

The UltraBattery technology is a less expensive, alternative hybrid energy storage device that can be used with hybrid electric vehicles. It has a longer life span than traditional lead-acid batteries and acts as a buffer during high-rate discharge and charge. It can also be used to deliver smooth power output from dirty power generation in renewable sources such as wind or solar. The UltraBattery technology can serve across DoD or the Army as a direct replacement to any instance where a lead-acid battery is currently being utilized.

2.5.2.3 Operating and functional limitations

The UltraBattery technology is subject to the same extreme temperature operational concerns as traditional batteries. The dilute sulfuric acid solution inside the battery has the potential to freeze at low temperatures. Additionally, time spent operating at very high or very low states of charge increases the side reactions in the electrochemical cells of the battery, which are detrimental to the battery's health, although the UltraBattery system does perform better than traditional lead-acid systems at partial states of charge.

2.5.2.4 Cold regions suitability

Along with all other battery technologies, operating at extreme low temperatures leads to a decrease in battery efficiency. No cold-weather-specific systems were identified in the commercial market. However, with proper precautions (i.e., keeping the battery operating within a safe operational temperature range by insulating or heating the UltraBattery system), this technology could be adapted for cold regions.

2.5.2.5 Average market cost of UltraBattery systems

Reports for the average market cost of UltraBattery systems varies but tends to be within a total project cost range of $400–$600/kWh (Mongird et al. 2019). Ecoult claims that the price of an UltraBattery is up to 40% cheaper than a traditional lead-acid battery system; however, no specific costs nor scale are reported (Deign 2018).

2.5.2.6 Case studies

The King Island Renewable Energy Integration Project is a megawatt class, off-grid energy project that supplies power to the remote island community of King Island in Tasmania. It combines solar, wind, and diesel power generation with an uninterruptable power supply flywheel and an UltraBattery advanced energy storage system. The King Island Renewable Energy Integration Project supplies 65% renewable energy per annum and can deliver up to 100% renewable energy during optimal conditions (HydroTasmania 2017).

As explained by Bender et al. (2015), the Public Service Company of New Mexico's 2011 Prosperity energy storage project was funded by DOE, and the Public Service Company of New Mexico sought to do the following:

- "Demonstrate that intermittent, renewables-based, distributed generation and storage can mitigate voltage-level fluctuations and enable peak shifting."
- "Quantify and refine performance requirements, operating practices, and cost associated with the use of advanced storage technologies."
- "Achieve 15 percent or greater peak-load reduction through a combination of substations-sited photovoltaics and storage."

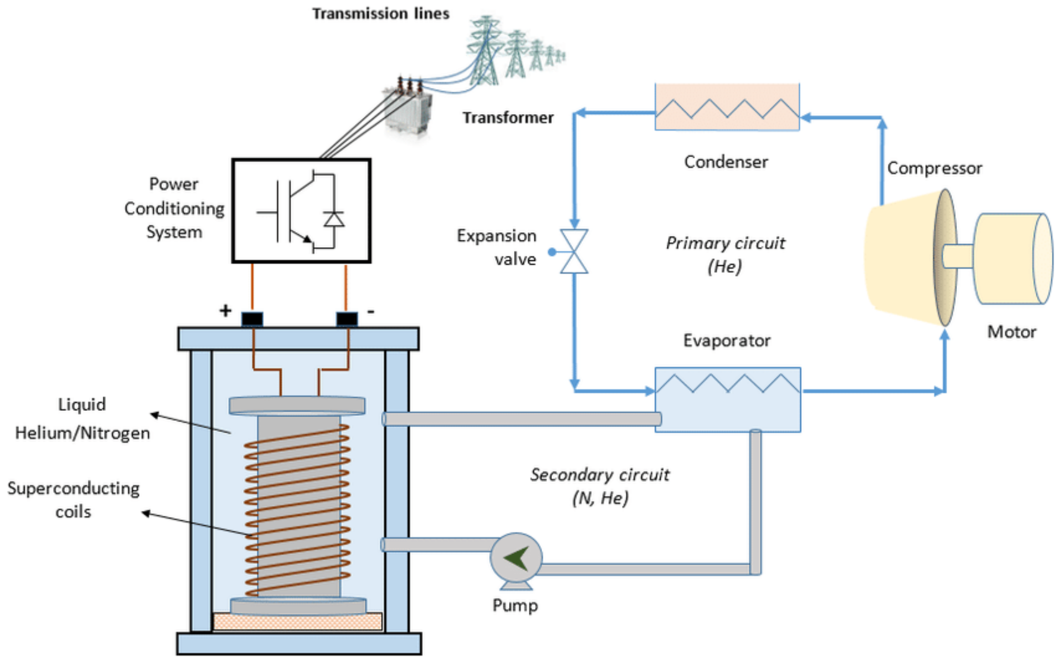
This project incorporated two battery systems: one UltraBattery-based system for power and one advanced lead-acid battery system for energy storage (Bender et al. 2015). Both systems were developed by Ecoult / East Penn. The UltraBattery system was used for smoothing and rated at 500 kW for 40 minutes, while the advanced lead-acid battery system was used for peak shifting and rated at 250 kW for 4 hours (Bender et al. 2015).

2.5.3 Superconducting magnetic energy storage

2.5.3.1 Description of technology

Superconducting magnetic energy storage (SMES) is a system that stores energy in a magnetic field created by the flow of a direct current in a superconducting coil. It consists of three parts: a superconducting coil, a power conditioning system, and a cryogenically cooled refrigerator. Figure 25 shows the schematic diagram of an SMES system.

Figure 25. Schematic diagram of a superconducting magnetic energy storage system. (Image reproduced from Nikolaidis and Poullikkas 2017. CC BY 3.0.)



2.5.3.2 *Applications and services*

SMES systems are highly efficient, showing efficiencies greater than 95%; and once charged, the current will not decay, and the magnetic energy can be stored indefinitely. SMES systems exhibit an immediate response, with very short time delays in both charge and discharge. There are no moving parts in the system and very little loss of power, making them a highly reliable source of clean power (Nikolaidis and Poullikkas 2017). This type of system would be appropriate for DoD or Army applications where energy storage is needed over a short duration (as discussed in the next section) or when clean high-quality power is necessary.

2.5.3.3 *Operating and functional limitations*

To operate at these high efficiencies and maintain their superconducting properties, the system must be kept cryogenically cooled (–250°C or below). The energy requirement to maintain this refrigeration and the high cost of superconductors and superconducting wire means that these systems are currently used for only short-duration energy storage or improving power quality in high-tolerance manufacturing plants (Nikolaidis and Poullikkas 2017). The energy content within the magnetic field is relatively small, so very strong magnetic fields are required to store the larger amounts of energy that would be needed to supply a facility. For example, a 1 GWh SMES system would need a superconducting wire loop of 161 km, all contained within a vacuum flask of liquid hydrogen, to produce a magnetic field strong enough to store the amount of energy required (Nikolaidis and Poullikkas 2017). This wire is looped back upon itself, so the physical size of the system is not 161 km; but with the high cost of rare earth metals (niobium, titanium, yttrium, or barium) needed in the manufacturing of superconductors and superconducting wire, it is unsurprising that the costs of these systems can be so high ($45 million for a 277 kWh system) (Zhu et al. 2013).

2.5.3.4 Cold regions suitability

As defined by MIL-STD-810G (DoD 2008), severe low temperatures (down to –51°C) are still much higher than the temperatures needed to keep a SMES system cryogenic (–250°C or below). As such, the energy demand for maintaining cryogenic temperatures at a cold region facility would be essentially the same as maintaining cryogenic temperatures at any other facility. This means that the system is just as suitable for a warm region facility as it is for a cold region facility.

For DoD or Army applications, this means that SMES technology could be applicable for any installation, regardless of location, and still have roughly the same operational costs. These systems do have a drawback for cold regions, however. Because of the high Lorentz forces that result from producing a magnetic field this strong, these systems are typically embedded into bedrock underground (Hassenzahl 1989). In cold regions, where it can be difficult to contend with frozen ground or shifting permafrost, this physical limitation could prohibit use of this technology.

2.5.3.5 Average market cost of superconducting magnetic energy storage systems

According to a 2013 study on the design and cost of SMES systems for power grids, a 277 kWh SMES system would have a total cost of approximately $45 million (Zhu et al. 2013). This works out to about $162,000/kWh. With advances in manufacturing of key components of SMES systems, including superconducting wire, refrigeration, etc., this cost would likely decrease.

2.5.3.6 Case studies

SMES systems are commonly used by manufacturing plants that require ultraclean power, such as microchip fabrication facilities (Nikolaidis and Poullikkas 2017). Akhil et al. (1997) estimated that a commercial 2.2 kWh system developed by Superconductivity Inc. cost an estimated $2.4 million in 1997.

In 1989, the Defense Nuclear Agency, on behalf of the Strategic Defense Initiative Office, called for proposals for SMES systems (Hassenzahl 1989). Two contracts were awarded to teams from two companies: Bechtel and Ebasco. The resulting Engineering Test Model was a large SMES system with a capacity of approximately 20 MWh (Schoenung 1993). This system was capable of providing 40 MW of power for 30 minutes or 10 MW of power for 2 hours (Schoenung 1993). This system involved several key structures: the superconductor and coil, the Dewar and structure that houses the refrigeration, the tunnel and excavation that the Dewar is located in, the cryogenic system that keeps the superconductor and coil cryogenic, and the power conditioning system (Hassenzahl 1989). The superconductor and coil sit inside of the cryogenic system and the vacuum-insulated Dewar system, which is embedded into rock underground. All of this connects to the power conditioning system, which connects to a power grid.

3 Installation Case Studies

The project team selected three installations for this project: Fort McCoy in Wisconsin; the ERDC-CRREL campus in Hanover, New Hampshire; and, the CRREL Permafrost Tunnel Research Center in Fox, Alaska. The identified installations provide diverse applications for this project (e.g., different climates, different operational demands, and different levels of remoteness).

For each of the installations consulted for this project, the ERDC project team gather data to inform potential applications for electrical energy storage system technologies in support of the installation's mission. Section 3.1 describes the data collected. Using this information and the technology assessment in section 2, the project team conducted a high-level assessment of the potential technologies, costs, and benefits of implementing an EES system. While this work leveraged the DOE-funded publication *Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage Systems* (Conover et al. 2016), which others have previously used to establish military energy storage system specifications, it is important to note that the assessments provided in the current technical report are meant to be illustrative.

Should an installation choose to implement an EES technology, it would require a much more detailed analysis for the precise technology selection and application identified to provide a more accurate cost-benefit assessment. Further, depending on the application identified, the information needed for such an assessment could require an appropriate classification of the analysis (e.g., controlled unclassified information, protecting it from public disclosure for security reasons). Thus, the approach taken here to illustrate how EES systems can serve an installation and the benefits that can result from such an investment is informed by information provided by the representative installations but not presented in sufficient detail to warrant classification.

3.1 Installation data collection

The project team selected the installations used in this case study because they are geographically distinct and experience different climates. To collect energy storage requirements and energy usage data for each installation, the project team contacted either the facilities' department of public works office or an installation lead who had access to these data. The personnel contacted had access to all historic electrical usage and capacity data that were available for the installation. To ensure data collection was standardized across sites, the project team developed an Energy Storage Analysis Data Requirement questionnaire, with input from DOE's Energy Storage Program. The questionnaire guided the general information required to perform a techno-economic evaluation for energy storage options. These case studies were high-level techno-economic assessments, and filling any additional data gaps and providing direct ESS advice to the installation was beyond the scope of this study. Each project is unique, and the data collection questionnaire may be adjusted on a case-by-case basis. Table 3 outlines the questionnaire used in this study, and Appendix A provides the questionnaire in full.

Table 3. Overview of the Energy Storage Analysis Data Requirement questionnaire showing each category and the type of data collected.

Category	Overview
Energy storage system (ESS) objectives	Determines the installation's energy storage goals (e.g., cost-saving, energy resiliency, or both) that will help weigh the benefits of each ESS option and identify upfront limitations (e.g., transmission limitations)
Economic objectives	Identifies the economic scope of the project and expectations for return on investment
Technical evaluation needs and facility energy load needs	Identifies the resolution of installation power supply and usage data (e.g., monthly utility bills for the entire installation or hourly metered electrical data for each building), allowing for budgeting additional data collection if required
Utility bills/ energy costs	Identifies for the installation the cost of power that will be used in the economic evaluation
Installation infrastructure	Identifies what documents are available for campus wiring diagrams and cybersecurity requirements
Critical infrastructure	Identifies critical infrastructure for the facility, resolution of power requirements, and resiliency requirements (e.g., number of days the system should be designed to supply power to the critical infrastructure during an outage).
On-site generation	Identifies active on-site energy generation and storage options
Grid connectivity	Identifies interconnectivity requirements and ESS integration options
Skilled personnel on-site for installation and management	Identifies skilled personnel on-site to install and maintain the ESS system

3.2 System Advisor Model overview

For each case study, the project team analyzed the information using the System Advisory Model (SAM), an open-source techno-economic modeling software that facilitates decision-making for projects that involve renewable energy and storage (NREL 2020). This tool was chosen for this project because it is freely available and provides a straightforward approach to using available information for a high-level assessment of each of the case studies. SAM is a tool NREL developed that facilitates decision-making for people in the renewable energy industry, such as project managers, engineers, researchers, and developers. SAM is available for download at no cost with a desktop application for Windows, Linux, and Mac OS. This tool allows users to choose both a performance and a financial model to represent a project. The user can then determine the variables to input into the model for such information as the location, the energy system, cost of installation and operation, and potential incentives or tax credits. It is also possible to leave certain parameters as the default value if the user has no information on it for their project. After all the variables have been inputted, the user runs the simulation and can examine the results. If any changes are necessary, the user simply revises the inputs and runs the simulation again (Blair et al. 2018).

SAM can model multiple types and combinations of renewable energy and energy storage systems from small residential solar arrays to large utility-scale systems. Users can also investigate battery storage systems with Li-ion, lead-acid, or flow batteries as well as fuel cells, wind power, marine energy, geothermal, biomass, and several other technologies. Additionally, SAM contains financial models for three types of projects. One type is residential and commercial projects where the energy system is on the customer's side of the electric utility meter and the system is used to reduce the customer's utility bill. The second type is for power purchase agreement projects where the system is connected to the grid and the project earns revenue through power sales. The third type is for third-party ownership where the customer hosts the system on their property and a separate entity owns it and compensates the host for the power generation (Blair et al. 2018). Figure 26 shows an example of the resulting simulation analysis from SAM for a PV-battery system in Homer, Alaska.

Figure 26. SAM's results summary for a PV-battery system in Homer, Alaska.

The project team used SAM primarily to perform a basic cost analysis for the installation case studies. The project team inputted into SAM data collected from the installations as described in section 3.1 and performed an example simulation with a desired energy storage system. Since limited data was available for some of the installations, the tool was very useful due to many of the parameters having a default setting. This allowed for a simulation despite the lack of specific inputs pertaining to the case study.

3.3 Fort McCoy, Wisconsin

3.3.1 Installation description

Fort McCoy is a U.S. Army Installation located in Monroe County in southwest Wisconsin. The hottest month is July, with an average high of 28°C and low of 16°C. The coldest month is January, with an average high of −3°C and low of −14°C (Your Weather Service 2021). (Your Weather Service 2021). On average, the area gets 864 mm of rain and 1041 mm of snow annually. Snowfall here is well above the national average of 711 mm per year (Best Places, n.d.).

Founded in 1909, Fort McCoy was originally divided into two camps (Camp Emory Upton and Camp Robinson) separated by a line of the Chicago, Milwaukee, St. Paul, and Pacific Railroad running east to west across the installation. Its size has grown from 5660 hectares in its infancy (U.S. Army 2018) to over 24,280 hectares today (Military OneSource 2020). In 1926, the two camps were joined to form Fort McCoy, named after Robert B. McCoy, a distinguished World War I veteran who initiated the purchasing of land and the foundation of the military installation that would eventually become Fort McCoy. Over the course of its history, it has primarily served as a military training center, which is still its primary use today (U.S. Army 2018).

Post–World War II, the installation went through periods of deactivation and reactivation during times of conflict. Since 1973, it has remained an active military base. McCoy is now also known as the Total Force Training Center (U.S. Army 2018). It hosts several large-scale annual exercises, including WAREX (Warrior Exercise—focused on platoon-level tactics), CSTX (Combat Support Training Exercise—focused on company-level training), Global Medic, and Operation Cold Steel (gunnery training) (First Army Division West 2020). During winter months, the installation runs the CWOC (Cold-Weather Operations Course) (Sturkol 2019).

3.3.2 Energy storage needs

A public utility company, Xcel Energy, provides Fort McCoy's electricity.* The installation has approximately 1800 buildings spread across more than 24,280 hectares of land. Because of this, as well as constraints imposed by contractual agreements with the utility company, it is more feasible to install smaller-scale energy storage solutions. Larger storage solutions that would, for example, serve transformer stations fed by the public utilities may not be allowed due to opaqueness of ownership boundaries.

Additionally, because of the current contract, the installation is able to sell back to the grid only a very small quantity of energy generated on-site. This makes selling back energy to the grid a negligible economic consideration in this scenario.

The utility bills do, however, provide an opportunity for peak shaving. Costs during peak hours and peak seasons are much higher per kilowatt

* Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

than during off-peak times. Additionally, because of Fort McCoy's widely variable temperatures, its usage surges during peak seasons.*

Fort McCoy also has fairly favorable solar conditions in the summer (NREL, n.d.). The installation is working towards energy resiliency and, as such, has a solar garden installed on one of its buildings along with a backup generator.

Given the above information, this analysis focuses on a combination of a smaller, discrete PV arrays coupled with energy storage to serve a high-demand building, as using smaller PV installations has been a successful solution for Fort McCoy in the past. The analysis compares Li-ion storage and fuel cells. The analysis also considers how peak shaving techniques may reduce costs.

3.3.3 Analysis and recommendations

Fort McCoy's public electricity service is essentially subdivided into two areas: (1) the ranges and outlying training areas and (2) the main cantonment area. Its electricity bills reflect this. The utility company does not meter the main cantonment area below the substation level. Therefore, the most granular load data available for this analysis is in the monthly electricity bills for the ranges, which are broken down by range and facility. Figure 27 graphs Fort McCoy's total monthly electrical load compared with its associated cost from October of 2017 through August of 2019.†

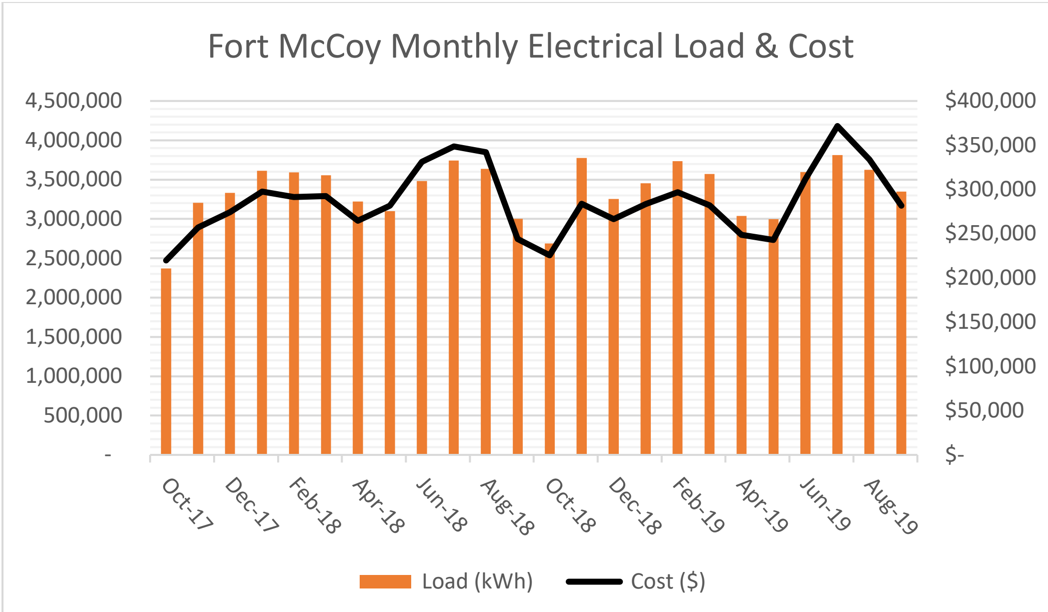
The peaks for both load and cost occur in winter and summer, as expected. However, the load peak in the summer is more exaggerated than in the winter, likely because the installation is heated by a separate natural gas system. The cost per kilowatt-hour also increases in the summer. Figure 27 shows this as the cost line rises above the load bars in the summer months. As an example, in July 2018, electricity cost $0.093/kWh; and in November 2018, it cost $0.075/kWh. As a result, despite higher consumption in November (3.78 million kWh) than in July (3.74 million kWh), the total cost in July was much higher ($349k vs. $284k in November).‡

* Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

† Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

‡ Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

Figure 27. Graph of Fort McCoy's monthly total electrical load vs. cost.



Data source: Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

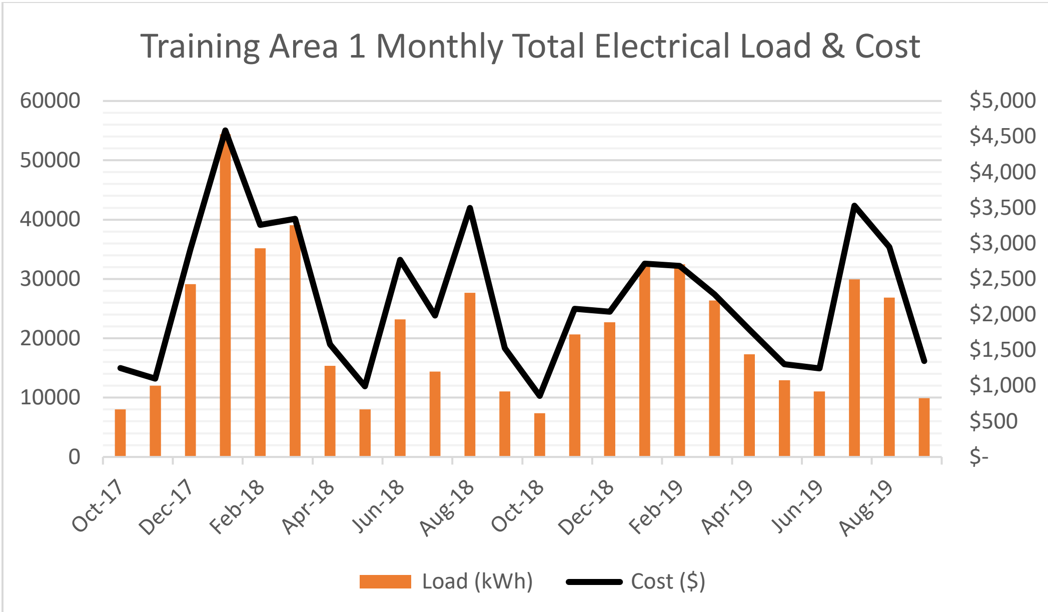
As it is more feasible to implement a small-scale storage system at Fort McCoy, this analysis will look at implementing a PV array at one of the training areas (referred to here as Training Area 1 [TA1]) with the highest annual demand and cost. Figure 28 graphs TA1's total monthly electrical load compared with its associated cost from October of 2017 through August of 2019. Again, its peaks are in the summer and winter, although they are more variable than the installation as a whole.* This is likely due to its variability of use as compared to facilities like barracks, dining facilities, or office spaces.

The project team examined two scenarios by using SAM. This gave a rough order estimate on the financial viability of energy storage and PV combinations. As only utility bills were available from the installation, the scenarios used many default values in SAM for the inputs. All default values included in SAM are estimated through market and scientific research by NREL and are therefore a good starting point for rough estimates. The scenarios tested included the following:

1. PV with Li-ion battery storage
2. PV with solid oxide fuel cell (SOFC) run off of hydrogen fuel

* Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

Figure 28. Graph of TA1's monthly total electrical load vs. cost.*



The project team examined Li-ion as a potential storage option due to its wide commercial availability, slow loss of charge when not in use, and high energy and power density, as discussed in section 2.1.1. While this battery type has many positive attributes, it does experience cold-weather degradation when charged at low temperatures and, therefore, requires thermal management (section 2.1.1). However, it has also been proven in various scenarios that systems can be designed to overcome this storage technology's weakness (e.g., section 2.1.1.6 discussion on the Saft battery system case study).

An SOFC system was also examined because of its fuel cells' high energy and power density (section 1.1). Additionally, while the effect of cold weather on fuel cells has not been extensively researched (section 2.2.1), it offers promise in cold regions because of its ability to cogenerate electrical and thermal energy (section 2.2.1). This fuel-cell example uses hydrogen fuel, generated by electrolysis from the PV panels; however, fuel cells can accept many different fuel sources. While the relationship with the utility provider in this situation likely would not allow integration with the grid, natural gas (McCoy's thermal energy source) could also be used to fuel a fuel cell. Additionally, it is possible to sell back the waste heat to the grid if the utility provider would allow this. So, while this scenario is not looking

* Xcel Energy, Fort McCoy utility bills, 2017–2019, unpublished data.

at these potential benefits, SOFCs and fuel cells in general are versatile energy storage technologies that could benefit cold regions installations in many regards.

SAM has NREL's National Solar Radiation Database embedded into the program so users can download site-specific solar irradiation data from within the SAM interface. Fort McCoy, Wisconsin, was not in the database, so the analysis used solar data from the vicinity of the installation. The data came from station ID 833568 at latitude 44.01°, longitude −90.66°. Nameplate capacities of 20% were used for both the PV and energy storage capacities. The peak demand at Fort McCoy's TA1 is 147 kW. Therefore, a nameplate capacity of 30 kW (direct current), 30 kWh, and 30 kW was used for the PV system, Li-ion battery bank capacity, and fuel-cell capacity, respectively.

The PV system design parameters assumed a fixed roof-mount system with a tilt of 44° (corresponding with the site's approximate latitude). The azimuth was assumed to be 180°, which is typical for sites north of the equator (samHelp). (NREL 2020). Default values in SAM were used to estimate system losses (Table 4). The weather data for Fort McCoy did not contain snowfall data; and therefore, these calculations assume the solar panels are ground mounted and cleared routinely during winter. A degradation of 0.5% was used based off median degradation values for PV panels (Jordan and Kurtz 2012).

Table 4. PV system losses.

System Losses			
Soiling	2%	Connections	0.5%
Shading	3%	Light-induced degradation	1.5%
Snow	0%	Nameplate	1%
Mismatch	2%	Age	0%
Wiring	2%	Availability	3%
Total losses:			14.08%

A battery power of 7 kW was chosen, and a look-ahead peak shaving dispatch was used to capture the best outcome. This means that the system can perfectly predict when to dispatch electrical power based on the electrical-demand profile. System defaults were used for efficiency and degradation.

For the fuel-cell dispatch, day-ahead dispatching was also used. System defaults were used for efficiency. The default value of 20% degradation annually was used initially but changed to 10% degradation given a very large payback period. The fuel cell was modeled to be replaced when it degraded to 30% capacity. The simulation was started with the fuel cell already running, as fuel cells take time to power up and down. Thermal sell-back is an option for fuel cells but it was ignored in this scenario.

The ability to export power to the grid was disabled by zeroing out the input values since this added value is negligible in Fort McCoy's situation. Additionally, default values from SAM were used for the financial parameters and system costs. Debt was assumed to be 0% given that Fort McCoy is a federal institution and would likely not have debt. A straight-line depreciation model was selected instead of the default 5-year modified accelerated cost recovery system (MACRS) depreciation model, as federal installations do not qualify for this incentive (Elgqyist et al. 2018). Federal installations also do not qualify for the incentive tax credits, so values for those fields were also zeroed out (Elgqyist et al. 2018).

The monthly electrical load in kilowatt-hours for the most recently provided utility data (October 2018–September 2019) was input into SAM and normalized to a standard commercial warehouse load profile that is embedded in SAM. This was necessary as hourly load data was not available. The project team assumed that out of the available standard load profiles, the commercial warehouse would most closely resemble a range/training facility's load profile. The resulting peak loads (Table 5) were estimated through this normalization process.

Table 5. Monthly normalized peak load, Fort McCoy's TA1, October 2018–September 2019.

Month	Load (kWh)	Peak (kW)
Jan-19	32,160.00	95.89
Feb-19	32,480.00	103.89
Mar-19	26,400.00	76.96
Apr-19	17,280.00	58.27
May-19	12,960.00	42.73
Jun-19	11,040.00	47.10
Jul-19	29,920.00	131.79
Aug-19	26,880.00	110.81
Sep-19	9,920.00	41.03
Oct-18	7,360.00	23.34
Nov-18	20,640.00	68.56
Dec-18	22,720.00	71.36
Annual	**249,760.00**	**131.79**

The program's analysis used the rates reflected in the energy bills provided by Fort McCoy (Table 6).

Table 6. Energy rates for Fort McCoy, 2019.

Energy Costs	Monthly Rates	
	Jun–Sep	Oct–May
Energy Rates		
Customer charge per month ($/month)	$49.00	$49.00
Distribution demand charge ($/kWh)	$0.50	$0.50
On-peak demand secondary voltage ($/kWh)	$13.00	$11.00
On-peak secondary Energy charge ($/kWh)	$0.07521	$0.07021
Off-peak secondary Energy charge ($/kWh)	$0.05602	$0.05602
Delivery Service		
Customer charge per month ($/month):	$49.00	$49.00
Distribution demand charge ($/kWh):	$0.50	$0.50
On-peak demand secondary voltage ($/kWh):	$13.00	$11.00
On-peak secondary Energy charge ($/kWh)	$0.07521	$0.07021
Off-peak secondary Energy charge ($/kWh)	$0.05602	$0.05602

Both scenarios used an analysis time frame of 25 years. Table 7 shows some key results.

Table 7. Key analysis results from SAM.

Metric	PV + Li-Ion	PV + Fuel cell
LCOE (real) ($/kWh)	$0.13	$0.23
Electricity bill without system (year 1) ($)	$27,195.00	$27,195.00
Electricity bill with system (year 1) ($)	$23,506.00	$10,972.00
Net savings (year 1) ($)	$3,690.00	$16,224.00
Net present value ($)	$(23,371.00)	$(321,896.00)
Simple payback period (years)	16.8	N/A
Discounted payback period (years)	N/A	N/A

Both scenarios indicate a negative net present value over the 25-year analysis window. For the PV with fuel-cell system, this is likely because the fuel cell needs to be replaced every 8 years based off the input parameters. As a result, the costs are much higher, and the analysis does not find a payback period within the 25-year window. The PV with Li-ion system has a 16.8 year simple payback period even though the net present value over the 25 years is negative. This is because the simple payback period does not discount future cash flows. When including a discount rate, the net present value is −$23,371, and accordingly there is no payback period within the 25-year analysis window.

To optimize this analysis, more design input information is needed. Additionally, because fuel cells used in conjunction with PV and battery systems show a lot of promise, their efficiency and utility have the potential to increase in the future. Further, with PV costs decreasing, such systems will become increasingly cost-effective.

3.4 CRREL main campus, Hanover, New Hampshire

3.4.1 Installation description

ERDC-CRREL is a U.S. Army Corps of Engineers research facility headquartered in Hanover, New Hampshire (CRREL-NH), which employs around 220 Army civilians. To support the U.S. Army's mission, CRREL aims to "solve scientific and engineering challenges in cold and complex environments through effective, interdisciplinary solutions for our warfighters and the Nation" (ERDC, "CRREL," n.d.). CRREL-NH has an elevation of 170 m, an average temperature range of −8.1°C (January) to 20.2°C (July), and an average rainfall of 931 mm (Climate-Data.org, n.d.). CRREL-NH's campus is composed of seven main office buildings, one that houses a cold room complex that contains 13 laboratory-grade cold rooms capable of maintaining temperatures ranging from −30°C to 43°C and four standalone cold rooms that can extend to −40°C. Additionally, there are larger standalone environmentally controlled chambers that facilitate additional functional requirements (Marina Reilly-Collette, CRREL, pers. comm., 15 December 2020):

- The Ice Engineering Research Area houses the 36.5 m × 9 m × 3 m Test Basin, a 45.7 m× 1.5 m× 1.2 m River Simulation Flume, and a 48.7 m × 36.5 m × 6 m Research Area. Historically, these facilities were capable of maintaining temperatures down to −29°C; however, they are currently nonoperational with ongoing plans for upgrades.
- The Geospatial Research Facility is an outdoor 18.2 m × 6.7 m × 2.1 m basin with a retractable roof that creates an insulated cold space above the basin. It is capable of maintaining temperatures ranging from 0°C to −20°C for the growth of a freshwater or saltwater ice sheet.
- The Material Engineering Facility is an 18.3 m × 6.7 m × 3.9 m insulated cold room capable of maintaining temperatures ranging from 15°C to −30°C.
- The Frost Effects Research Facility is a 121.92 m × 15.2 m × 3.9 m refrigerated warehouse capable of maintaining temperatures down to −12°C.
- The Greenhouse Research Facility includes a 167.2 m^2 polyacrylic greenhouse and 250.8 m^2 of laboratory, office, and storage space.

3.4.2 Energy storage needs

As an Army research facility, CRREL-NH has critical infrastructure that must remain operational when service is disrupted; and it must meet the Army's 14-days resilience requirements. CRREL-NH receives power from local utilities and, like any utility customer, is vulnerable to blackouts or other disruptions in this service. Currently, diesel generators supply backup power; however, these are subject to supply chain disruption. CRREL-NH may benefit from having energy storage as stand-alone systems or coupled with renewable energy production to ensure mission readiness under most power-disruption scenarios. Additionally, being stationed in a cold climate and having large cold-capable research facilities provide CRREL-NH the opportunity to test large power storage systems for the Army before they are installed on active military bases.

To conduct a cost analysis for energy storage technologies at CRREL-NH, electrical utilities data were collected through ERDC's department of public works at CRREL-NH. The utility data had resolution down to the month that encompassed the entire campus. CRREL-NH would require additional instrumentation to increase the resolution to the week or day per building. The CRREL-NH campus uses approximately 6.5 million kWh of electricity per year with an average of 537,600 kWh per month. CRREL-NH spends $746,000.00 in electrical utilities annually with an average of $62,200.00 per month.

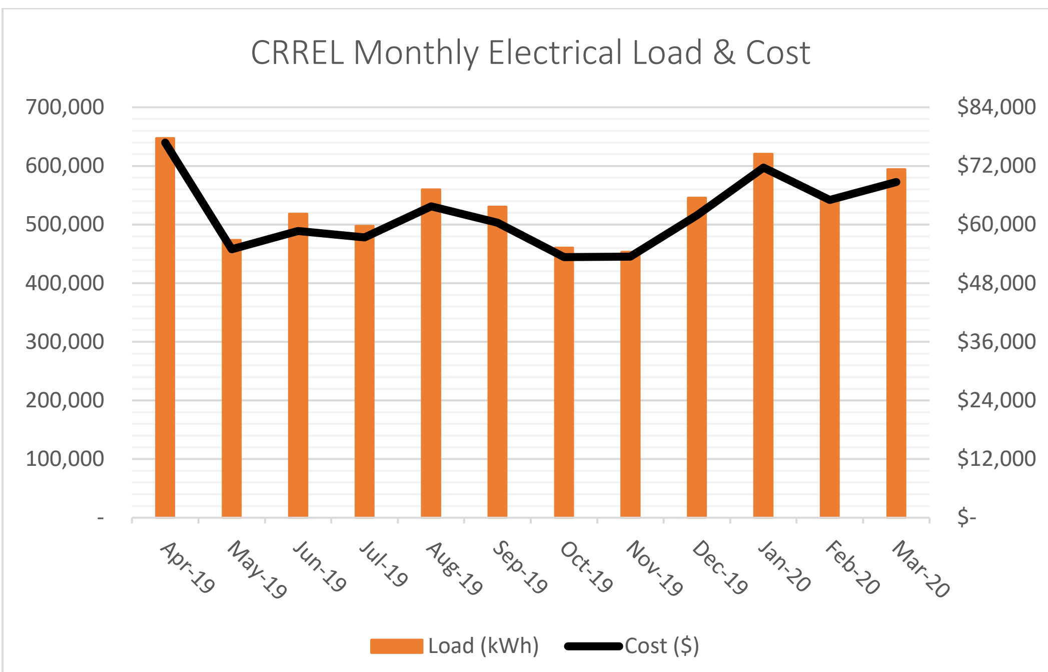
3.4.3 Analysis and recommendations

The information provided in section 2 guided the ESS selection process for this analysis. CRREL-NH experiences cold winters with weeks to months of subfreezing conditions. This would make hydrogen energy storage or pumped hydro storage systems difficult to implement as any water used or produced would be subject to ice formations, limiting the functional capabilities of the system. There is little performance data on hydrogen energy storage coupled with warming mechanisms in cold regions as mentioned in section 2.2.1. Using LAES seems technologically feasible given its cold storage requirements; however, at this time the technology shows promise at the megawatt or grid scale but shows low round-trip efficiencies at the kilowatt or campus scale. LAES also has a short discharge time of 8–12 hours and would not be able to meet the 14-day resilience requirements set by the Army without being coupled to a renewable energy source. LAES is a nascent technology, and estimating installation cost at a military base is difficult at this time.

The project team focused on PV coupled with Li-ion rechargeable battery storage given its technological maturity and potential for long-term storage in cold conditions with system modifications, such as batteries that incorporate advanced insulation materials and a hydronic heating coil developed by Saft (section 2.1.1). The cost analysis for CRREL-NH was performed using SAM (NREL 2020).

The utility company that supplies power to CRREL-NH does not meter beyond the substation level, and CRREL-NH does not have additional metering in place. The most granular load data available for this project were monthly electric bills from April 2019 to March 2020. CRREL-NH's critical infrastructure is powered by backup generators during outage events, and the maximum power output specifications of this system were used in the critical infrastructure section of the cost-analysis. CRREL-NH pays a fixed rate for electricity that is independent of peak and off-peak fluctuation in cost; therefore, it was not feasible to investigate load shifting using energy storage as a cost-benefit option. As an alternative, the project team investigated renewable power generation coupled with energy storage options. For the analysis, the project team determined whether CRREL-NH could use energy storage for (1) the entire campus or (2) critical infrastructure only. Critical infrastructure includes loads that must remain operational during a power disruption and receive power from backup generators during an outage. It is difficult to predict power-outage events based on the data gathered for this project; therefore, the analyses were treated as if the renewable power and energy storage would serve the campus load all year.

Figure 29. Graph of CRREL-NH monthly electrical load and utilities cost from April 2019 to March 2020.*



In 2019–2020, CRREL-NH had a peak energy usage and cost in April 2019 and January 2020 (Figure 29) and did not display summer and winter peak usage that is typically found in industrial and office campuses of similar size. CRREL-NH is a reach facility with the majority of on-site research conducted in refrigerated facilities with high energy usage, which

* Constellation Energy, CRREL utility bills, 2020, unpublished data; Liberty Utilities, CRREL utility bills, 2019, unpublished data.

may be represented in the irregular energy usage patterns. CRREL-NH pays a fixed energy rate of $0.117/kWh, hence the monthly cost is closely tied to energy usage (Figure 29).

For this study, the cost analysis serves as an example and is not final guidance for CRREL-NH investment options. This is a high-level analysis, and many of the modeling parameters in SAM were left as default. The program allows the user to import solar data based on region. For this parameter, latitude 43.73° and longitude –72.26° were used for Hanover, New Hampshire. Adjustments made to system and battery capacity, battery runtime, and electricity rate were made based on utility data for the CRREL-NH campus and total generator capacity for the critical infrastructure scenario. The peak demand for the CRREL-NH campus during the sample period was 1225 kW. To buffer any growth or fluctuation in usage, the system nameplate capacity for the campus-wide analysis in SAM was set to 1750 kWDC. The total capacity of the CRREL-NH backup generator system is 1040 kWDC, this value was used as the system nameplate capacity for the critical infrastructure analysis. For both analyses, the Li-ion battery system was designed to meet the peak demand for 24 hours. This is likely an overestimate of the system requirements but was used as a worst-case scenario. To obtain a more accurate assessment would require hourly resolution on electrical usage at CRREL-NH's facilities. Table 8 outlines system design input to SAM for both scenarios.

Table 8. System design parameters for the campus-wide and critical infrastructure models in SAM.

System	Campus-wide	Critical Infrastructure
System nameplate capacity (kWDC)	1750	1040
Module type	Standard	Standard
DC to AC ratio	1.2	1.2
Rated inverter size (kWAC)	1458.33	866.67
Inverter efficiency (%)	96	96
Battery capacity (kWh)	42,000	24,000
Battery power (kW)	1750	1040

The PV system design parameters assumed a fixed open rack system with a tilt of 20° (corresponding with the site's approximate latitude). The azimuth was assumed to be 180° and a ground cover ratio of 0.4%. Default values in SAM were used to estimate system losses and are the same as for the Fort McCoy analysis in the previous section (Table 4). The weather data for CRREL-NH did not contain snowfall information, and it was assumed that the solar panels are cleared routinely during winter. A degradation of 0.5% was used based on median degradation values for PV panels (Jordan and Kurtz 2012).

CRREL-NH electrical cost of $0.117/kWh was input into SAM, and a normalized warehouse model was used to represent CRREL-NH's load profile. This was necessary because the granularity of the load data was monthly, not hourly. For the campus-wide analysis, a scaling factor of 9 was used to match load requirement; and for the critical infrastructure analysis, a scaling factor of 1 was used. The resulting peak loads were estimated through this normalizing process (Table 9).

Table 9. Monthly normalized peak load, CRREL-NH (campus-wide), April 2019–March 2020.

	Campus wide		Critical Infrastructure	
Month	Load (kWh)	Peak (kW)	Load (kWh)	Peak (kW)
Jan	516,055.41	2112.08	57,339.49	234.68
Feb	437,015.84	1560.80	48,557.32	173.42
Mar	501,750.75	1548.06	55,750.08	172.01
Apr	477,134.38	1722.91	53,014.93	191.43
May	544,146.69	1784.66	60,460.75	198.29
Jun	631,371.06	2128.22	70,152.34	236.47
Jul	699,376.19	2468.08	77,708.46	274.23
Aug	697,995.44	2343.02	77,555.05	260.34
Sep	556,143.06	2040.76	61,793.68	226.75
Oct	519,232.31	1666.11	57,692.48	185.12
Nov	466,607.53	1405.80	51,845.28	156.20
Dec	489,046.78	1656.45	54,338.53	184.05
Annual	6,535,875.50	2468.08	726,208.38	274.23

As expected, the cost analysis indicated that investing in a campus-wide PV and battery system has a high capital cost (Table 10). Given its lower capital investment, using PV and battery storage to support critical infrastructure may be the first step to building a campus-wide project.

CRREL-NH is located in a cold climate at a high latitude where batteries generally lose the ability to hold a charge, and PV arrays experience shorter winter day that reduces their functionality. System modifications to improve the performance of Li-ion batteries, such as the Saft Intensium

Max+ 20M with cold weather package (Saft 2017), still require testing before they are ready for military installations. They need to be assessed for their ability to support cold climate installations and the integration of legacy assets. The CRREL-NH campus was constructed in 1961; and like many military installations, it has a variety of legacy assets (including many of the cold facilities mentioned above). CRREL-NH can leverage these assets to assess the best methods for integrating ESS on a military installation without putting active warfighters at risk. The cost of renewables and energy storage options are expected to decrease over time and will allow for wider applications of this energy generation and storage technology. The project team recommends that CRREL-NH (1) further investigates opportunities to gain better resolution on its power usage and (2) explores its renewable power generation and energy storage options to support its critical infrastructure while collecting performance data on PV and Li-ion battery technology in cold climates for the DoD. The net present value accounts for inflation and assesses the profitability of an investment based on a given timeline (e.g., the payback period on investment). Based on the payback period used for this analysis, the investment would be at a loss of $2.9 million and $2.2 million for the CRREL campus-wide and critical infrastructure analyses, respectively (Table 10).

Table 10. Cost analysis results from the SAM model for each CRREL scenario.

System	Campus-Wide	Critical Infrastructure
Annual energy (kWh) (year 1)	2,080,488	1,256,324
Capacity factor (%) (year 1)	14.0	14.0
Energy yield (kWh/kW) (year 1)	1228	1228
Battery round-trip efficiency (%)	88.68	81.54
Battery charge energy from system (%)	2.0	70.9
LCOE (nominal) ($/kWh)	0.25	0.23
LCOE (real) ($/kWh)	0.19	0.17
Electricity bill without system (year 1)	$7,215,898	$1,826,790
Electricity bill with system (year 1)	$6,972,481	$1,742,166
Net savings with system (year 1)	$243,417	$84,625
Net present value	−$2,961,643	−$2,218,637
Net capital cost	$13,101,080	$7,785,786
Equity	$5,240,432	$3,114,314
Debt	$7,860,648	$4,671,472

3.5 CRREL Permafrost Tunnel Research Facility, Fox, Alaska

3.5.1 Installation description

The Permafrost Tunnel Research Facility is located near the Goldstream Creek in Fox, Alaska, 25 km north of Fairbanks. Although the permafrost in the region is not continuous, the area near the Goldstream and Glenn Creeks provided continuous permafrost for the excavation of the tunnel.

The Permafrost Tunnel Research Facility is approximately 350 m long, 4 to 5 m wide, 4 to 5 m tall and averages 15 m below the surface. The tunnel is composed of two adits (horizontal passages), a crosscut connecting the north and south adits, and two winzes (inclined adits). The gravel room at the bottom of the winze is approximately 5 m lower than the adit, making it sloped. Engineers originally used the tunnel to test underground excavation techniques in permafrost. The north adit was excavated during the winters of 1963 and 1964, and the winze (minor connection between different levels in the tunnel) was excavated in 1968–1969. The south adit was constructed during the winters of 2011 and 2013, and the crosscut was excavated during 2018.

It was during the excavation process that the tunnel's usefulness as a laboratory for natural science and engineering study became clear. The walls of the tunnel show a complete record of undisturbed, continuously frozen silt, sand, and gravel on top of bedrock, all rich in fossils. Animal fossils and plant remains, such as beetles, mites, flies, moths, butterflies, and snail shells are seen frozen in the walls throughout the tunnel. Bones and teeth of bison, mammoth, and horse are some of the other visible fossils. Also exposed in the tunnel are a variety of ground ice types, including ice wedges, thermokarst cave ice, and ice lenses (ERDC, "Permafrost," n.d.). The tunnel has recently been going through an upgrade and an expansion. During the winter of 2020, an additional 150 m of tunnel was excavated, almost doubling the area of exposed permafrost. This expansion increases research capacity of the facility and provides access to more research material.

3.5.2 Energy storage needs

The Permafrost Tunnel Research Facility is well situated to be an example of how to operate a facility using energy sustainability. With its unique characteristics and requirements, the tunnel has the potential to showcase different energy storage technologies suited for remote locations and research operations.

To preserve what is contained within the tunnel for future research, the refrigeration technique changes depending on the season. During the summer, the refrigeration system is made up of two compressors that maintain the cold within the tunnel. During the winter, the cold ambient air from outside is blown into the tunnel via fans. It is imperative that the tunnel remains frozen to prevent a collapse, keeping personnel safe while inside and preserving the structure for research. Since the facility is tied to the grid, a power outage could lead to serious problems if not addressed quickly.

Additional energy needs at the tunnel include the lights, sensors, meteorological stations, and baseboard heaters. Energy storage can also help reduce overall facility energy costs at the Permafrost Tunnel Research Facility by reducing peak energy needs to regain and maintain a residential electric rate verses a commercial electric rate. There is also the potential for a ground-source heat pump system to heat existing and future facilities by taking advantage of the large temperature difference between the air and the ground.

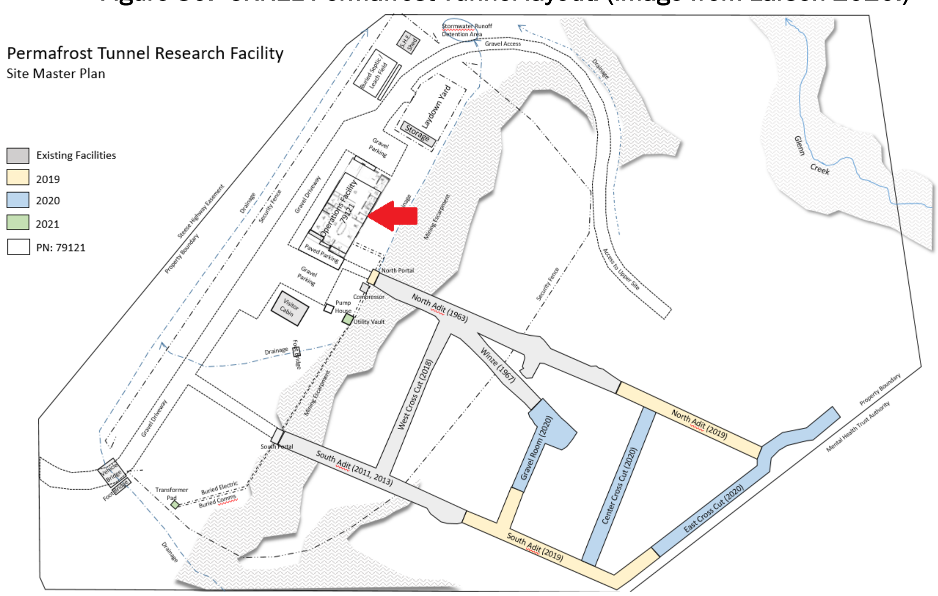
The project team considered energy storage at the Permafrost Tunnel Research Facility to help demonstrate how a remote research facility can be run in a resilient and sustainable way.

3.5.3 Analysis and recommendations

Because of the Permafrost Tunnel Research Facility's limited infrastructure, use of energy storage could be incorporated into future upgrades. Of the technologies discussed in section 2, there are several systems that would not be feasible for use at the Permafrost Tunnel Research Facility. With very limited available funding for operation and maintenance, large and expensive energy storage installations are not the optimal solution. A technology such as a redox flow battery system is not well suited for operation in this application, especially if the system uses a water-based electrolyte, due to the potential issues caused by freezing and ice formation. As the tunnel can experience temperatures down to −40°C, unless the system is insulated and the temperature is kept above the electrolytes freezing temperature, this technology is not a reliable solution for use at the tunnel. An ultracapacitor-based energy storage system could function at low temperatures; however, this is a very low-energy-density technology, so it would not be able to support a large electrical load. A potential alternative to this is to implement renewable energy generation, such as solar panels, coupled with a rechargeable battery system, such as a small Li-ion battery bank. The goal would to be use the sun during the warm summer months to store energy, which would then power the compressors that cool the tunnel. The stored energy could also power the lights inside the tunnel and the fans used during the winter. A battery energy storage system would provide the facility with energy reliability no matter the conditions.

Given the age and state of the tunnel, there is very little documentation of the loads and configuration of the system. There is a master plan layout that includes building locations and plans for future electric transmission lines, shown in Figure 30.

Figure 30. CRREL Permafrost Tunnel layout. (Image from Larsen 2020.)



Currently, there is work at the tunnel to install an array of solar panels at as part of a resilient energy systems congressional add project. This is the only form of renewable energy generation the site has currently, so there is no existing infrastructure to store the generated solar energy. There is plenty of space on-site for a battery storage system, whether in an existing shed or a new one if needed. The long-term solution would be to incorporate the battery energy storage system into the operations facility, which is the main building for tunnel operations (indicated by the red arrow in Figure 30).

The project team conducted a cost analysis for the Permafrost Tunnel by using NREL's SAM tool for a combined PV and battery energy storage system as an example. This is a simplified analysis as only utility bills for the tunnel were available, so many of the parameters were set as the tool's default value. Homer, Alaska, was selected for the location of the analysis because the data set for the available solar resource used by the tool does not contain data for the Permafrost Tunnel Research Facility's location in Fox, Alaska. SAM uses NREL's National Solar Radiation Database for site-specific solar-irradiation data. Because this data set extends only partially into Alaska, an alternative location was needed; and Homer, Alaska, was the closest option to the Permafrost Tunnel Research Facility.

The PV system design was a two-axis tracking system, which was selected to capture as much solar energy as possible. This system tracks the sun's direction throughout the day, allowing it to capture more energy than a fixed-tilt system. The default values for system losses in SAM were used for this analysis, except for losses due to snow (shown in Table 11). The percent of losses due to snow was found to be upwards of 40% in the northern parts of Alaska (Ryberg 2017) due to large amounts of snow accumulating on the panels.

Table 11. PV system losses.

System Losses			
Soiling	2%	Connections	0.5%
Shading	3%	Light-induced degradation	1.5%
Snow	40%	Nameplate	1%
Mismatch	2%	Age	0%
Wiring	2%	Availability	3%
Total losses			48.45%

The annual energy consumption at the tunnel is approximately 36,600 kWh, so for the PV-battery energy storage system to supply that, the following parameters were inputted into SAM (Table 12).

The Permafrost Tunnel Research Facility monthly energy usage based on the utility bills was inputted into SAM to get the monthly load summary and to determine peak loads, shown in Table 13.

Table 12. CRREL Permafrost Tunnel cost analysis information.

Metric	Value
Latitude	59.65
Longitude	−151.54
System Capacity	46 kWDC
Battery Capacity	72 kWh
Battery Power	10 kW
Utility Charge Rates	0.115 $/kWh

Table 13. Monthly normalized peak load for the Permafrost Tunnel, January 2018–December 2018.

Month	Load (kWh)	Peak (kW)
Jan-19	2910.00	7.17
Feb-19	4638.00	12.71
Mar-19	6591.00	18.49
Apr-19	4572.00	16.30
May-19	3357.00	11.60
Jun-19	1866.00	6.56
Jul-19	1337.00	3.61
Aug-19	1259.00	3.79
Sep-19	1254.00	4.52
Oct-18	1795.00	5.46
Nov-18	2735.00	7.32
Dec-18	4351.00	11.14
Annual	**36,665.00**	**18.49**

The cost analysis shows that, based on these parameters, there is a high capital cost associated with using a PV and battery storage to meet all the energy needs at the CRREL Permafrost Tunnel. There is also so little solar resource available at such a high latitude that there is no reasonable payback period for this size installation. Table 14 shows the results obtained from the cost analysis.

This scenario results in a negative net present value, likely due to the high cost of the system. As a result, the net capital cost is higher, and there is not a feasible payback period. Based on these results, the project team does not recommend that the entire tunnel's energy needs be supported by a PV and battery storage system. It would be much more beneficial to utilize an energy storage system to operate the refrigeration system to maintain the tunnel's temperature, as stated earlier in this section. The project team recommends further investigation into the options for energy storage at the CRREL Permafrost Tunnel prior to upgrading the infrastructure. The project team also suggests collecting more data on energy needs and existing infrastructure before moving forward.

Table 14. CRREL Permafrost Tunnel cost analysis results from SAM.

Metric	PV + Li-Ion
LCOE (real)	0.17 $/kWh
Electricity bill without system (year 1)	$6673.00
Electricity bill with system (year 1)	$1778.00
Net savings (year 1)	$4895.00
Net present value	−$18,334.00
Simple payback period (years)	N/A
Discounted payback period (years)	N/A
Net Capital Cost	$155,987.00

4 Conclusion

Energy storage systems are a valuable resource to support resilience at Army installations in all climates. This work focused specifically on the technological potential of various energy storage systems to support those in cold regions. However, for these environments, limited information is available about many energy storage technologies that are either commercially available or nascent. Table 15 summarizes the more mature energy storage technologies reviewed in section 2 and their potential for use in cold regions. Some technologies need additional systems (e.g., thermal management) while others may need further research to better understand the technology's full cold regions potential.

Table 15. Summary of energy storage technologies and their cold regions potential.

Technology	Cold Regions Potential
Rechargeable Batteries*	Needs thermal management
Redox Flow Batteries*	Facility-scale applications; needs thermal management
Solid-State Battery	Not currently capable; more info needed
Hydrogen (Fuel Cells)	Not currently suitable; membrane ice damage
Hydrogen Peroxide (Propellant)	Freezable; stability issues as liquid fuel; likely not suitable
Flywheels*	Potential depending on materials used
Pumped Hydro Storage*	Ice damage and safety issues; requires design/ operation considerations
Compressed-Air Energy Storage	Limited examples; more info needed
Liquid-Air Energy Storage*	Potential depending on design; more info needed
Thermal Energy Storage	Limited examples; more info needed
Ultracapacitor*	Low-temperature vehicle-start assistance
UltraBattery*	Decreased efficiency; needs thermal management
Superconducting Magnetic Energy Storage	Unstable ground challenges; requires cryogenic refrigeration (≤−250 °C)

* DoD Potential

Use of available energy storage technologies has the potential to improve Army installation resilience by providing more consistent and reliable power to critical installation infrastructure and, potentially, broader infrastructure and operations. However, the specific application of any energy storage technology depends on the needs for the specific installation.

Section 2.5.2 assessed three case studies. In each case, the need of the installation with respect to potential energy storage applications is different (e.g., adapt with legacy systems, foresight for new infrastructure planning, or leveraging current energy system technology advancements). For each of the installations considered, data availability and granularity posed an important challenge to fully evaluating the business case and understanding the financial implications of incorporating energy storage into the installation's energy systems. It is important to note that, while the assessments provided are illustrative, any future consideration of energy storage systems at these installations would require a more detailed analysis. It would need to address the specific application with current energy use data with sufficient granularity (e.g., 15-minute intervals) to determine the true suitability of an energy storage technology for the installation. Such a detailed analysis was beyond the scope of this effort but is an important element of selecting an appropriate energy storage technology.

For those installations seeking to determine which energy storage system technologies best meets their need, the installation must consider several metrics to support the analysis (see section 3.1 and the Appendix A for more information):

- Energy storage system objectives
- Economic objectives
- Technical evaluation needs and facility energy load needs
- Utility bills and energy costs
- Installation infrastructure
- Critical infrastructure
- On-site generation
- Grid connectivity
- Personnel on-site for installation and management

As noted throughout sections 2 and 2.5.2, more work is needed to understand not only the technical potential of some energy storage technologies but to also understand how they can be further developed to meet cold regions applications at Army installations. This work may involve cold performance testing of existing systems where performance is not yet known or development of appropriate thermal management systems to complement existing energy storage technologies, enabling them to support Army missions in cold regions. Further, details about a specific installation application and energy need must be evaluated to better inform the business-case assessment of an energy storage technology with technical potential to support an Army installation. Section 3.1 describes much of what information is needed to support such an analysis.

Overall, energy storage systems will play an important role in Army installation resilience. With an understanding of the technology's needed capabilities in cold regions, appropriate energy storage systems can likely be configured to reliably operate and support mission resilience in such climates.

References

Active Power. 2021. “Cleansource HD UPS.” Active Power. Accessed 21 February 2021. https://www.activepower.com/en-US/2937/cleansource-hd-u2028-ups.

Akhil, A., G. Huff, A. Currier, B. Kaun, D. Rastler, S. Chen, A. Cotter, D. Bradshaw, and W. Gauntlett. 2013. *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*. SAND 2013-5131. Albuquerque, NM, and Livermore, CA: Sandia National Laboratories. https://www.energy.gov/sites/default/files/2013/08/f2/ElecStorageHndbk2013.pdf.

Akhil, A., S. Swaminathan, and R. K. Sen. 1997. *Cost Analysis of Energy Storage Systems for Electric Utility Applications*. Albuquerque, NM: Sandia National Laboratories. https://www.osti.gov/servlets/purl/453759.

Alaska Center for Energy and Power. 2012. *Composite Flywheels for Energy Storage*. Fairbanks, Alaska: University of Alaska Fairbanks, Alaska Center for Energy and Power. http://acep.uaf.edu/media/281485/CompositeFlywheels_Hatch.pdf.

Al-Juboori, S. A., and H. Y. Al-Shawwreh. 2018. “Solar Energy Assessment of Molten Salts as Thermal Storage Mediums.” In *Proceeding of 13th International Scientific Forum*, 4–6 October, 331–351. Fez, Morocco: International Scientific Forum. https://eujournal.org/files/journals/1/books/13th.ISF.Morocco.pdf.

Alnaimat, F., and Y. Rashid. 2019. “Thermal Energy Storage in Solar Power Plants: A Review of the Materials, Associated Limitations, and Proposed Solutions.” *Energies* 12 (21): 4164. https://doi.org/10.3390/en12214164.

Alotto, P., M. Guarnieri, and F. Moro. 2014. “Redox Flow Batteries for the Storage of Renewable Energy: A Review.” *Renewable and Sustainable Energy Reviews* 29:325–335. https://doi.org/10.1016/j.rser.2013.08.001.

Alvarado, J. L., C. Marsh, C. Sohn, G. Phetteplace, and T. Newell. 2007. “Thermal Performance of Microencapsulated Phase Change Material Slurry in Turbulent Flow under Constant Heat Flux.” *International Journal of Heat and Mass Transfer* 50 (9–10): 1938–1952. https://doi.org/10.1016/j.ijheatmasstransfer.2006.09.026.

Amazon. n.d. “Maxwell ULTRA31/1800 Group 31 Engine Starting Module ESM Battery 12V DC 1800 CCA.” Amazon. Accessed 27 January 2020. https://www.amazon.com/Maxwell-ULTRA31-Engine-Starting-Battery/dp/B00WT75NG8.

Anderson, R., L. Bates, E. Johnson, and J. F. Morris. 2015. “Packed Bed Thermal Energy Storage: A Simplified Experimentally Validated Model.” *Journal of Energy Storage* 4 (December): 14–23. https://doi.org/10.1016/j.est.2015.08.007.

Andrews, J., and S. S. Mohammadi. 2014. “Towards a ‘Proton Flow Battery’: Investigation of a Reversible PEM Fuel Cell with Integrated Metal-Hydride Hydrogen Storage.” *International Journal of Hydrogen Energy* 39 (4): 1740–1751. https://doi.org/10.1016/j.ijhydene.2013.11.010.

Awad, A., A. Burns, M. Waleed, M. Al-Yasiri, and D. Wen. 2018. "Latent and Sensible Energy Storage Enhancement of Nano-Nitrate Molten Salt." *Solar Energy* 172 (2): 191–197. https://doi.org/10.1016/j.solener.2018.04.012.

Barbir, F. 2005. "PEM Electrolysis for Production of Hydrogen from Renewable Energy Sources." *Solar Energy* 78 (5): 661–669. https://doi.org/10.1016/j.solener.2004.09.003.

Battery University. 2017. "BU-410: Charging at High and Low Temperatures." Battery University. Last modified 15 September 2017. https://batteryuniversity.com/learn/article/charging_at_high_and_low_temperatures.

Beacon Power. 2014. *Beacon Power Flywheel Energy Storage Systems*. Tyngsboro, MA: Beacon Power, LLC. https://beaconpower.com/wp-content/themes/beaconpower/inc/beacon_power_brochure_032514.pdf.

Beacon Power and Chugach Electric. 2015. "Beacon Power and Chugach Electric Association to Deploy Hybrid Flywheel and Battery Energy Storage Project in Alaska." Press release, 26 May 2015. https://beaconpower.com/wp-content/uploads/2015/05/Beacon_Chugach-MS-ESS-Press-Release_FINAL.pdf.

Bender, D., R. Byrne, and D. Borneo. 2015. *ARRA Energy Storage Demonstration Projects: Lessons Learned and Recommendations*. SAND2015-5242. Albuquerque, NM: Sandia National Laboratories. https://www.sandia.gov/ess-ssl/publications/SAND2015-5242.pdf.

Best Places. n.d. "*Climate in Sparta, Wisconsin.*" Best Places. Accessed 6 June 2021. https://www.bestplaces.net/climate/city/wisconsin/sparta.

Bielecki, A., S. Ernst, W. Skrodzka, and I. Wojnicki. 2019. "Concentrated Solar Power Plants with Molten Salt Storage: Economic Aspects and Perspectives in the European Union." *International Journal of Photoenergy* 2019: 8796814. https://doi.org/10.1155/2019/8796814.

Blair, N., N. DiOrio, J. Freeman, P. Gilman, S. Janzou, T. Neises, and M. Wagner. 2018. *System Advisor Model (SAM) General Description*. NREL/TP-6A20-70414. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy18osti/70414.pdf.

Boicea, V. A. 2014. "Energy Storage Technologies: The Past and the Present." In *Proceedings of the IEEE* 102 (11): 1777–1794. https://doi.org/10.1109/JPROC.2014.2359545.

Braff, W. A., M. Z. Bazant, and C. R. Buie. 2013. "Membrane-less Hydrogen Bromine Flow Battery." *Nature Communications* 4:2346. https://doi.org/10.1038/ncomms3346.

Breeze, Paul. 2019. "Power Systems Energy Storage Technology." In *Power Generation Technologies (Third Edition)*, 219–249. Cambridge, MA: Newnes. https://doi.org/10.1016/C2017-0-03267-6.

Brett, G., and M. Barnett. 2014. "The Application of Liquid Air Energy Storage for Large Scale Long Duration Solutions to Grid Balancing." *EPJ Web of Conferences* 79:03002. http://dx.doi.org/10.1051/epjconf/20137903002.

Bullis, K. 2014. “Nanoparticle Networks Promise Cheaper Batteries for Storing Renewable Energy.” *MIT Technology Review*, 24 April 2014. https://www.technologyreview.com/s/526811/nanoparticle-networks-promise-cheaper-batteries-for-storing-renewable-energy/.

Business Wire. 2019. “HighviewPower and Encore Renewable Energy to Co-Develop First Long Duration, Liquid Air Energy Storage System in the United States.” *Business Wire*, 18 December 2019. https://www.businesswire.com/news/home/20191218005156/en/.

Byrne, M. 2016. “Behold: The World’s Largest Battery.” *Vice*, 27 August 2016. https://motherboard.vice.com/en_us/article/z43q49/behold-the-worlds-largest-battery.

Chandler, D. L. 2011. “Go with the Flow.” *MIT Technology Review*, 23 August 2011. https://www.technologyreview.com/s/425107/go-with-the-flow/.

Climate-Data.org. n.d. “Hanover Climate.” Climate-Data.org. Accessed 28 July 2020. https://en.climate-data.org/north-america/united-states-of-america/new-hampshire/hanover-25696/.

Conover, D., A. J. Crawford, J. Fuller, S. N. Gourisetti, V. Viswanathan, S. Ferreira, D. Schoenwald, and D. M. Rosewater. 2016. *Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage Systems*. PNNL-22010. Richland, Washington: Pacific Northwest National Laboratory. https://doi.org/10.2172/1249270.

Danigelis, A. 2019. “First Long-Duration Liquid Air Energy Storage System Planned for the US.” *Environment +Energy Leader*, 19 December 2019. https://www.environmentalleader.com/2019/12/liquid-air-energy-storage-first/.

Datta, B. K., G. Velayutham, and A.Prasad Goud. 2002. “Fuel Cell Power Source for a Cold Region.” *Journal of Power Sources* 106 (1–2): 370–376. https://doi.org/10.1016/S0378-7753(01)01024-2.

De Leon, C., A. Frias-Ferrer, J. Gonzalez-Garcia, D. Szanto, and F. Walsh. 2006. “Redox Flow Cells for Energy Conversion.” *Journal of Power Sources* 160 (1): 716–732. https://doi.org/10.1016/j.jpowsour.2006.02.095.

Deign, J. 2018. “After Long Period of Silence, Ecoult Returns to Multi-Megawatt Battery Market.” *Greentech Media*, 3 May 2018. https://www.greentechmedia.com/articles/read/ecoult-returns-to-multi-megawatt-battery-market.

Dockter, J., D. Vandor, D. Beck, and G. Larson. 2017. *Cost-Effective, High-Efficiency 70 MW Energy Storage Plant Based on Patented Pressurized Liquid Air Energy Storage (LAES) Technology Has Lower Cost of Energy Compared to Battery Energy Storage Systems*. Presented at the POWER-GEN International Conference, December 2017. Tarrytown, NY: Expansion Energy. http://www.expansion-energy.com/yahoo_site_admin/assets/docs/POWER-GEN_-_Expansion_Energy_LLC_-_VPS_Cycle_LAES_Technical_Paper_-_FINAL_DRAFT.33873916.pdf.

DoD (U.S. Department of Defense). 2008. *Environmental Engineering Considerations and Laboratory Tests*. MIL-STD-801G. Washington, DC: Department of Defense. https://www.atec.army.mil/publications/mil-std-810g/mil-std-810g.pdf.

DOE (U.S. Department of Energy). n.d. "Hydrogen Storage." Office of Energy Efficiency and Renewable Energy. Accessed 12 March 2020. https://www.energy.gov/eere/fuelcells/hydrogen-storage.

———. n.d. "Linear Concentrator System Concentrating Solar-Thermal Power Basics." Office of Energy Efficiency and Renewable Energy, Solar Energy Technologies Office. Accessed 2 February 2021. https://www.energy.gov/eere/solar/linear-concentrator-system-concentrating-solar-thermal-power-basics.

———. n.d. "Pumped-Storage Hydropower." Office of Energy Efficiency and Renewable Energy, Water Power Technologies Office. Accessed 8 March 2020. https://www.energy.gov/eere/water/pumped-storage-hydropower.

———. 2014. "*2014: The Year of Concentrating Solar Power*." DOE/EE-1101. Washington DC: U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2014/10/f18/CSP-report-final-web.pdf.

DOE (U.S. Department of Energy) Office of Energy Efficiency and Renewable Energy. 2011. *Report of the DOD-DOE Workshop on Converting Waste to Energy Using Fuel Cells: DOD-DOE MOU Workshop Summary and Action Plan*. Washington DC: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. https://www.energy.gov/sites/prod/files/2014/03/f12/waste_to_energy_report.pdf.

Drouilhet, S, and B. L Johnson. 1997. *A Battery Life Prediction Method for Hybrid Power Applications*. NREL/CP-440-21978. Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory. https://www.nrel.gov/docs/legosti/fy97/21978.pdf.

Ebrahimi, M., and A. Keshavarz. 2015. "3 - CCHP Evaluation Criteria." In *Combined Cooling, Heating, and Power*, 93–102. Elsevier. https://doi.org/10.1016/B978-0-08-099985-2.00003-2.

Electronics Tutorials. 2021. "Ultracapacitors." Electronics Tutorials. https://www.electronics-tutorials.ws/capacitor/ultracapacitors.html.

Elgqvist, E., K. Anderson, and E. Settle. 2018. *Federal Tax Incentives for Energy Storage Systems*. NREL/FS-7A40-70384. Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy18osti/70384.pdf.

Enos, D. G. 2014. *Lead-Acid Batteries and Advanced Lead-Carbon Batteries*. SAND2014-17394B, 537276. Albuquerque, NM: Sandia National Laboratories. https://www.osti.gov/servlets/purl/1502636.

ERDC (U.S. Army Engineer Research and Development Center). n.d. *CRREL Mission—Vision*. U.S. Army Corps of Engineers Engineer Research and Development Center (website). Accessed 27 July 2020. https://www.erdc.usace.army.mil/Locations/CRREL/Missions/.

———. n.d. Permafrost Tunnel Research Facility Description. U.S. Army Corps of Engineers Engineer Research and Development Center (website). Accessed 24 April 2020. https://www.erdc.usace.army.mil/CRREL/Permafrost-Tunnel-Research-Facility/Description/.

First Army Division West. 2020. "181st Infantry Brigade." First Army Division West. Accessed 22 September 2020. https://www.first.army.mil/divwest/content.aspx?ContentID=181.

Fritsch, A., C. Frantz, and R. Uhlig. 2019. “Techno-Economic Analysis of solar Thermal Power Plants Using Liquid Sodium as Heat Transfer Fluid.” *Solar Energy* 177: 155–162. https://doi.org/10.1016/j.solener.2018.10.005.

Fuel Cells and Hydrogen Joint Undertaking. 2020. “About the Project.” BIGHIT. Accessed 19 March 2020. https://www.bighit.eu/about.

Galant, S., E. Peirano, and L. Debarberis. 2013. “Electricity Storage: A New Flexibility Option for Future Power Systems.” In *Advanced Technologies for Future Transmission Grids*, edited by G. Migliavacca, 247–284. London: Springer. http://dx.doi.org/10.1007/978-1-4471-4549-3_7.

Gebre, S., K. Alfredsen, L. Lia, M. Stickler, and E. Tesaker. 2013. “Review of Ice Effects on Hydropower Systems.” *Journal of Cold Regions Engineering* 27 (4). https://ascelibrary.org/doi/10.1061/%28ASCE%29CR.1943-5495.0000059.

Gravity Energy AG. n.d. “Research and Demonstration Plant Weilheim (Upper Bavaria, Germany).” Gravity Energy AG. Accessed 4 November 2020. http://gravityenergyag.com/research-and-demonstration-plant-weilheim-upper-bavaria-germany/?lang=en.

Gyuk, I. 2013. “Grid Energy Storage -- DOE Update.” United States Energy Association. Accessed 5 April 2020. https://usea.org/sites/default/files/event-/Gyuk_USDOE_Energy_Storage_Technologies.pdf.

Hall, P. J., and E. J. Bain. 2008. “Energy-Storage Technologies and Electricity Generation.” *Energy Policy* 36 (12): 4352–4355. https://doi.org/10.1016/j.enpol.2008.09.037.

Harg, K. 2005. “Utsira—Demonstrating the Hydrogen Society on Renewable Terms.” *Hydrogen Ambassadors*. Presented at the 4th International Conference, Hydrogen + Fuel Cells Hannover Fair, 12 April 2005. http://www.hydrogenambassadors.com/hm05/conference/utsira.pdf.

Harrison, K. W., G. D. Martin, T. G. Ramsden, and W. Kramer. 2009. *The Wind-to-Hydrogen Project: Operational Experience, Performance Testing, and System Integration*. NREL/TP-550-44082. Golden, CO: National Renewable Energy Lab. https://doi.org/10.2172/951802.

Hassenzahl, W. V. 1989. “Superconducting Magnetic Energy Storage.” *IEEE Transactions on Magnetics* 25 (2): 750–758. https://doi.org/10.1109/20.92399.

Herrmann, U., B. Kelly, and H. Price. 2004. “Two-tank molten salt storage for parabolic trough solar power plants.” *Energy* 29 (5–6): 883–893. https://doi.org/10.1016/S0360-5442(03)00193-2.

Highview Power. n.d. “Plants.” Highview Power. Accessed 18 March 2020. https://www.highviewpower.com/plants/.

Holcomb, F. H. 2008. *Proceedings of the 1st Army Installation Waste to Energy Workshop*. ERDC/CERL TR-08-11. Washington, DC: U.S. Army Corps of Engineers. http://hdl.handle.net/11681/20147.

Holcomb, F. H., J. Bush, J. L. Knight, and J. Whipple. 2007. "Energy Savings for Silent Camp™ Hybrid Technologies." *Journal of Fuel Cell Science and Technology* 4 (2): 134–137. https://doi.org/10.1115/1.2714566.

Huang, C.-K., J. S. Sakamoto, J. Wolfenstine, and S. Surampudi. 2000. "The Limits of Low-Temperature Performance of Li-Ion Cells." *Journal of The Electrochemical Society* 147 (8): 2893–2896. https://doi.org/10.1149/1.1393622.

Hunt, G., and J. Szymborksi. 2009. "Achievements of an ABSOLYTE® Valve-Regulated Lead-Acid Battery Operating in a utility Battery Energy Storage System (BESS) for 12 Years." Presented at Electrical Energy Storage Applications and Technologies 2009 Conference, 4–7 October, Seattle, Washington. https://www.sandia.gov/ess-ssl/EESAT/2009_papers/Achievements%20of%20an%20ABSOLYTE%20Valve-Regulated%20Lead-Acid%20Battery.pdf.

Hydrostor. 2020. "A-CAES Projects." Hydrostor. Accessed 21 February 2021. https://www.hydrostor.ca/projects/.

HydroTasmania. 2017. "King Island Renewable Energy Integration Project (KIREIP)." Accessed 5 March 2020. https://www.hydro.com.au/docs/default-source/clean-energy/hybrid-energy-solutions/king_island.pdf?sfvrsn=f3ad4828_2.

Islam, M., H. Masjuki, M. Kalam, and N.W.M. Zulkifli. 2015. "A comprehensive review on biodiesel cold flow properties and oxidation stability along with their improvement processes." *RSC Advances* 105: 86631–86655. https://doi.org/10.1039/C5RA09555G.

Jain, P. 2017. *Energy Storage in Grids with High Penetration of Variable Generation*. Mandaluyong City, Philippines: Asian Development Bank. http://dx.doi.org/10.22617/TCS178669.

Jordan, D. C., and S. R. Kurtz. 2012. *Photovoltaic Degradation Rates: An Analytical Review*. NREL/JA-5200-51664. Golden, CO: U.S. Department of Energy: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy12osti/51664.pdf.

Kharel, S., and B. Shabani. 2018. "Hydrogen as a Long-Term Large-Scale Energy Storage Solution to Support Renewables." *Energies*. 11 (10). https://doi.org/10.3390/en11102825.

Kirby, B. 2004. *Frequency Regulation Basics and Trends*. Oak Ridge, TN: Oak Ridge National Laboratory. https://doi.org/10.2172/885974.

Kirby, B. J., J. Dyer, C. Martinez, R. A. Shoureshi, R. Guttromson, and J. Dagle. 2002. *Frequency Control Concerns in the North American Electric Power System*. ORNL/TM-2003/41. Oak Ridge, TN: Oak Ridge National Laboratory. https://doi.org/10.2172/885842.

Kosny, J., N. Shukla, and A. Fallahi. 2013. *Cost Analysis of Simple Phase*. DOE/GO-102013-3692. Oak Ridge, TN: U.S. Department of Energy. https://doi.org/10.2172/1219890.

Kovo, Y. 2021. "3.0 Power." In *State of the Art of Small Spacecraft Technology*. Last modified 25 January 2021. Washington, DC: National Aeronautics and Space Administration. https://www.nasa.gov/smallsat-institute/sst-soa-2020/power.

Krawczyk, P., L. Szablowski, E. Karellas, and K. Badyda. 2018. "Comparative Thermodynamic Analysis of Compressed Air and Liquid Air Energy Storage Systems." *Energy* 142 (1): 46–54. https://doi.org/10.1016/j.energy.2017.07.078.

Kuang, Y., M. J. Kenney, Y. Meng, W. Hung, Y. Liu, J. E. Huang, R. Prasanna, et al. 2019. "Solar-Driven, Highly Sustained Splitting of Seawater." *Proceedings of the National Academy of Sciences* 116 (14): 6624–6629.

Larsen, G. 2020. "ERDC CRREL Permafrost Tunnel Research Facility." PowerPoint presentation. Fairbanks, AK: U.S. Army Engineer Research and Development Center, Cold Regions Research and Engineering Laboratory.

Lee, Y. G., S. Fujiki, C. Jung, N. Suzuki, N. Yashiro, R. Omoda, D. S. Ko, et al. 2020. "High-Energy Long-Cycling All-Solid-State Lithium Metal Batteries Enabled by Silver–Carbon Composite Anodes." *Nature Energy* 5, 299–308. https://doi.org/10.1038/s41560-020-0575-z.

Legrand, M., L. M. Rodríguez-Anton, C. Martinez-Arevalo, and F. Gutierrez-Martín. 2019. "Integration of Liquid Air Energy Storage into the Spanish Power Grid." *Energy* 187:115965. https://doi.org/10.1016/j.energy.2019.115965.

Li, Y., H. Cao, S. Wang, Y. Jin, D. Li, X. Wang, and Y. Ding. 2014. "Load Shifting of Nuclear Power Plants Using Cryogenic Energy Storage Technology." *Applied Energy* 113:1710–1716. https://doi.org/10.1016/j.apenergy.2013.08.077.

Li, Z., P. Guo, R. Han, and H. Sun . 2019. "Current Status and Development Trend of Wind Power Generation-Based Hydrogen Production Technology." *Energy Exploration & Exploitation* 37 (1): 5–25. https://doi.org/10.1177/0144598718787294.

Luo, X., J. Wang, M. Dooner, and J. Clarke. 2015. "Overview of Current Development in Electrical Energy Storage Technologies and the Application Potential in Power System Operation." *Applied Energy* 137:511–536. https://doi.org/10.1016/j.apenergy.2014.09.081.

Mahlia, T. M., T. J. Saktisandan, A. Jannifer, M. H. Hasan, and H. S. Matseelar. 2014. "A Review of Available Methods and Development on Energy Storage; Technology Update." *Renewable & Sustainable Energy Reviews* 33:532–545. https://doi.org/10.1016/j.rser.2014.01.068.

Maxwell Technologies. 2014. *Maxwell Ultracapacitors. Changing How the World Stores and Uses Energy*. Document number 3000615-EN.2 San Diego, CA: Maxwell Technologies. https://www.maxwell.com/images/documents/Ultracapacitors_Overview_Flyer_3000615-2EN.pdf.

———. 2016. *How Ultracapacitors Improve Starting Reliability for Truck Fleets*. White paper. Maxwell Technologies.

———. 2021. "Maxwell Grid Energy Storage System." Maxwell Technologies. Accessed 17 February 2021. https://www.maxwell.com/products/ultracapacitors/grid-energy-storage-system.

McFadden, C. 2017. "These Cool Energy Storage Trains Simply Work with the Power of Gravity." *Interesting Engineering*, 4 May 2017. https://interestingengineering.com/energy-storage-trains-work-power-gravity.

McTigue, J., C. N. Markides, and A. J. White. 2018. "Performance Response of Packed-Bed Thermal Storage to Cycle Duration Perturbations." *Journal of Energy Storage* 19 (October): 379–392. https://doi.org/10.1016/j.est.2018.08.016.

Melaina, M., and J. Eichman. 2015. *Hyrogen Energy Storage: Grid and Transportation Services*. NREL/TP-5400-62518, Golden, CO: National Renewable Energy Laboratory. https://doi.org/10.2172/1170355.

Military OneSource. 2020. "Fort McCoy In-depth Overview." Military Installations. Accessed 22 September 2020. https://installations.militaryonesource.mil/in-depth-overview/fort-mccoy.

Mofijur, M., T. M. I. Mahlia, A. S. Silitonga, H. C. Ong, M. Silakhori, M. H. Hasan, N. Putra, and S. M. A. Rahman. 2019. "Phase Change Materials (PCM) for Solar Energy Usages and Storage: An Overview." *Energies* 12 (16): 3167. https://doi.org/10.3390/en12163167.

Mongird, K., V. Viswanathan, P. Balducci, J. Alam, V. Fotedar, V. Koritarov, and B. Hadjerioua. 2019. *Energy Storage Technology and Cost Characterization Report*. PNNL-28866. Richland, WA: U.S. Department of Energy: Pacific Northwest National Laboratory. https://doi.org/10.2172/1573487.

Morefield, S., and J. Alvarado. 2015. *Field Validation of Microencapsulated Phase-Change Material Slurries as Heat-Transfer Fluids*. Technical Memorandum EW-201154. Champaign, IL: U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory. https://www.serdp-estcp.org/Program-Areas/Installation-Energy-and-Water/Energy/Conservation-and-Efficiency/EW-201154/EW-201154-TM.

Morgan, R., S. Nelmes, E. Gibson, and G. Brett. 2015a. "An Analysis of a Large-Scale Liquid Air Energy Storage System." *Proceedings of the Institution of Civil Engineer—Energy* 168 (2): 135–144. https://doi.org/10.1680/ener.14.00038.

———. 2015b. "Liquid Air Energy Storage—Analysis and First Results from a Pilot Scale Demonstration Plant." *Applied Energy* 137 (1): 845–853. https://doi.org/10.1016/j.apenergy.2014.07.109.

Mouser Electronics. n.d. "Maxwell/Nesscap BCAP0350 P270 S18." Mouser Electronics. Accessed 27 January 2020. https://www.mouser.com/ProductDetail/Maxwell-Nesscap/BCAP0350-P270-S18?qs=BJlw7L4Cy7%252BLd6iIxIXMRg%3D%3D.

Muhando, B., and T. Johnson. 2012. *Advanced Battery Storage Systems Testing at ACEP, The Prudent Energy VRB-ESS: Characterization and Assessment of the Flow Battery Concept for Energy Storage and Ancillary Services in Isolated Wind-Diesel Power Networks in Alaska*. Fairbanks, AK: University of Alaska Fairbanks, Alaska Center for Energy and Power (ACEP). http://acep.uaf.edu/media/53140/ACEP-VRB-Testing-Report.pdf.

Nikolaidis, P., and A. Poullikkas. 2017. "Comparative Review of Electrical Energy Storage Systems for Better Sustainability." *Journal of Power Technologies* 9 (3): 220–245. https://papers.itc.pw.edu.pl/index.php/JPT/article/view/1096.

NREL (National Renewable Energy Laboratory). n.d. "NSRDB: National Solar Radiation Database." National Renewable Energy Laboratory. Accessed 28 January 2021. https://nsrdb.nrel.gov/.

———. 2017. "Gemasolar Thermosolar." *Concentrating Solar Power Projects*. Last modified 20 March 2017. https://solarpaces.nrel.gov/gemasolar-thermosolar-plant.

———. 2018. "Concentrating Solar Power." Annual Technology Baseline. Accessed 19 March 2020. https://atb.nrel.gov/electricity/2018/index.html?t=sc.

———. 2020. System Advisor Model Version 2020.11.29 (SAM 2020.11.29). Accessed 28 January 2021. Goldong, CO: National Renewable Energy Laboratory. https://sam.nrel.gov/.

Pacheco, J. E., T. Wolf, and N. Muley. 2013. *Incorporating Supercritical Steam Turbines into Molten-Salt Power Tower Plants: Feasibility and Performance*. SAND2013-1960, Albuquerque, NM: DOE Sandia National Labs. https://doi.org/10.2172/1088078.

Pan, F., and Q. Wang. 2015. "Redox Species of Redox Flow Batteries: A Review." *Molecules* 20 (11): 20499–20517. https://doi.org/10.3390/molecules201119711.

Pawel, I. 2014. "The Cost of Storage—How to Calculate the Levelized Cost of Stored Energy (LCOE) and Applications to Renewable Energy Generation." *Energy Procedia* 46:68–77. https://doi.org/10.1016/j.egypro.2014.01.159.

Pellow, M. A., C. J. M. Emmott, C. J. Barnhart, and S. M. Benson. 2015. "Hydrogen or Batteries for Grid Storage?" *Energy and Environmental Science* 8 (7): 1938–1952. https://doi.org/10.1039/C4EE04041D.

Power Technologies. 2021. "Crescent Dunes Solar Energy Project, Nevada." Power Technologies. Accessed 10 August 2021. https://www.power-technology.com/projects/crescent-dunes-solar-energy-project-nevada/.

Proczka, J. J, K. Muralidharan, D. Villela, J. H. Simmons, and G. Frantziskonis. 2013. "Guidelines for the pressure and efficient sizing of pressure vessels for compressed air energy storage." *Energy Conversion and Management* 65 (January): 597–605. https://doi.org/10.1016/j.enconman.2012.09.013.

PV Magazine. 2014. "Ideal Power and EnerDel to Develop a New Line of Mobile Hybrid Power Systems." *PV Magazine*, 10 September 2014. https://www.pv-magazine.com/press-releases/ideal-power-and-enerdel-to-develop-a-new-line-of-mobile-hybrid-power-systems_100016381/.

Qi, Z., and G. M. Koenig Jr. 2017. "Review Article: Flow Battery Systems with Solid Electroactive Materials." *Journal of Vacuum Science and Technology B*. 35 (4): 040801. https://doi.org/10.1116/1.4983210.

Raj, A. K. 2020. "Simulation of Thermodynamic Efficiency and Plant Equipment Finance for Cryogenic Energy Storage Systems as Applied to Medium to Large Scale Liquid-Air Electricity-Storage." *Journal of Research in Applied Chemistry* 3 (1): 1–17.

Reilly, H. E., and G. J. Kolb. 2001. *An Evaluation of Molten-Salt Power Towers Including Results of the Solar Two Project*. SAND2001-3674. Albuquerque, NM: Sandia National Labs. https://doi.org/10.2172/791898.

Ruoso, A. C., N. R. Caetano, and L. A. O. Rocha. 2019. "Storage Gravitational Energy for Small Scale Industrial and Residential Applications." *Inventions* 4 (4): 64. https://doi.org/10.3390/inventions4040064.

Ryberg, D., and J. Freeman. 2017. *Integration, Validation, and Application of a PV Snow Coverage Model in SAM*. NREL/TP-6A20-68705. Golden, CO: National Renewable Energy Laboratory. https://doi.org/10.2172/1374128.

Saft. n.d. *Saft Lithium Selector Guide.* Levallois-Perret, France: Saft. https://www.saftbatteries.com/market-sectors/aerospace-defense/defense#!documentation-and-downloads.

———. 2017. "Saft Li-Ion Energy Storage Plays Key Role in KEA's Alaskan Microgrid." Saft. Accessed 22 February 2021. https://www.saftbatteries.com/case-studies/saft-li-ion-energy-storage-plays-key-role-kea%E2%80%99s-alaskan-microgrid.

Sarbu, I., and C. Sebarchievici. 2018. "A Comprehensive Review of Thermal Energy Storage." *Sustainability* 10 (1): 191. https://doi.org/10.3390/su10010191.

Schmidt, O., S. Melchior, A. Hawkes, and L. Staffel. 2019. "Projecting the Future Levelized Cost ofElectricity Storage Technologies." *Joule* 3 (1): 81–100. https://doi.org/10.1016/j.joule.2018.12.008.

Schoenung, S. M. 1993. "Survey of U.S. SMES Development Programs." *Applied Superconductivity* 1 (7–9): 1443–1455.

Schoenung, S., R. H. Byrne, T. Olinsky-Paul, and D. R. Borneo. 2017. *Green Mountain Power (GMP): Significant Revenues from Energy Storage*. SAND2017-6164. Albuquerque, NM: Sandia National Labs. https://www.sandia.gov/ess-ssl/publications/SAND2017-6164.pdf.

Sciacovelli, A., A. Vecchi, and Y. Ding. 2017. "Liquid Air Energy Storage (LAES) with Packed Bed Cold Thermal Storage - From Component to System Level Performance through Dynamic Modelling." *Applied Energy* 190 (15): 84–98. https://doi.org/10.1016/j.apenergy.2016.12.118.

Seshie, Y. M., K. E. N'Tsoukpoe, P. Neveu, Y. Coulibaly, and Y. K. Azoumah. 2018. "Small scale concentrating solar plants for rural electrification." *Renewable and Sustainable Energy Reviews* 90 (July): 195–209. https://doi.org/10.1016/j.rser.2018.03.036.

Shultz, A. 2017. “Concentrating Solar Power Could Provide the Flexibility and Reliability the U.S. Electric Grid Needs.” U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 3 November 2017. https://www.energy.gov/eere/articles/concentrating-solar-power-could-provide-flexibility-and-reliability-us-electric-grid.

Smith, S. C., and P. K. Sen. 2008. “Ultracapacitors and Energy Storage: Applications in Electrical Power System.” In *2008 40th North American Power Symposium*, Calgary, Alberta, Canada, 28–30 September. https://doi.org/10.1109/NAPS.2008.5307299.

Staffell, I., D. Scamman, A. V. Abad, P. Balcombe, P. E. Dodds, P. Ekins, N. Shah, and K. R. Ward. 2019. “The Role of Hydrogen and Fuel Cells in the Global Energy System.” *Energy & Environmental Science* 12: 463–491. https://doi.org/10.1039/C8EE01157E.

Stepien, Tom. 2017. *Renewable Firming EnergyFarm Final Report*. Hayward, CA: Primus Power. https://doi.org/10.2172/1346202.

Steward, D., G. Saur, M. Penev, and T. Ramsden. 2009. *Lifecycle Cost Analysis of Hydrogen Versus Other Technologies for Electrical Energy Storage* . NREL/TP-560-46719. Golden, CO: National Renewable Energy Laboratory. https://doi.org/10.2172/968186.

Sturkol, S. 2019. “Army Rangers Complete Training in Cold-Weather Ops Course at Fort McCoy.” *DVIDS: Defense Visual Information Distribution Service*, 19 March 2019. https://www.dvidshub.net/news/314891/army-rangers-complete-training-cold-weather-ops-course-fort-mccoy.

Sun, W., Y. Hong, and Y. Wang. 2017. “Operation Optimization of Steam Accumulators as Thermal Energy Storage and Buffer Units.” *Energies* 10 (1): 17. https://doi.org/10.3390/en10010017.

Supercaptech.com. 2020. “The Difference Betweeen Battery VS Supercapacitor.” *Supercaptech.com*, 16 September 2020. https://www.supercaptech.com/battery-vs-supercapacitor.

Tarkowski, R. 2019. “Underground Hydrogen Storage: Characteristics and Prospects.” *Renewable and Sustainable Energy Reviews* 105 (May): 86–94. https://doi.org/10.1016/j.rser.2019.01.051.

The Weather Channel. 2020a. “Monthly Weather—Huntorf, Lower Saxony, Germany.” The Weather Channel. Accessed 22 September 2020. https://weather.com/weather/monthly/l/2c702e986dfac40775ceb08186226fe4eef114f28613138065aad17bc8304219.

———. 2020b. “Monthly Weather—Toronto, Ontario, Canada.” The Weather Channel. Accessed 22 September 2020. https://weather.com/weather/monthly/l/62e0efebee1ac0e8fa9b21fd17d57a6a0001753ab6be8a4874bb78bbb52eda02.

Tholander, M., and T. Högberg. 2018. “Utvärdering av flytande luft som ett energilagringsalternativ” [Evaluation of Liquid Air as an Energy Storage Alternative]. BS thesis, Royal Institute of Technology, School of Architecture and Civil Engineering.

Turrini, S., M. Bettonte, M. Eccher, M. Grigriante, A. Miotello, and R.S. Brusa. 2018. “An Innovative Small-Scale Prototype Plant Integrating a Solar Dish Concentrator with a Molten Salt Storage System.” *Renewable Energy* 123 (August): 150–161. https://doi.org/10.1016/j.renene.2018.02.053.

U.S. Army. 2016. *Army Installations 2025*. Washington, DC: Department of the Army, Installations, Energy, and Environment. http://www.asaie.army.mil/Public/ES/oei/docs/ASAIEE_Installations2025.pdf.

———. 2018. “U.S. Army Fort McCoy Total Force Training Center History.” Army.mil. Last modified 13 September 2018. https://home.army.mil/mccoy/index.php/about/history.

U.S. Energy Information Administration. 2011. “Electricity Storage Technologies Can Be Used for Energy Management and Power Quality.” *Today in Energy*, 14 December 2011. https://www.eia.gov/todayinenergy/detail.php?id=4310.

Ulleberg, O., T. Nakken, and A. Ete. 2010. “The Wind/Hydrogen Demonstration System at Utsira in Norway: Evaluation of System Performance Using Operational Data and Updated Hydrogen Energy System Modeling Tools.” *International Journal of Hydrogen Energy* 35 (5): 1841–1852. https://doi.org/10.1016/j.ijhydene.2009.10.077.

Usibelli Coal Mine. 1987. “UCM History: Usibelli Story.” Usibelli Coal Mine, 8 September 1987. http://www.usibelli.com/history/usibelli-story.

Valderrama, C., O. Gibert, J. Arcal, P. Solano, A. Akbarzadeh, E. Larrotcha, and J. L. Cortina. 2011. “Solar Energy Storage by Salinity Gradient Solar Pond: Pilot Plant Construction and Gradient Control.” *Desalination* 279 (1–3): 445–450. https://doi.org/10.1016/j.desal.2011.06.035.

Ventura, M., E. Wernimont, S. Heister, and S. Yuan. 2007. “Rocket Grade Hydrogen Peroxide (RGHP) for use in Propulsion and Power Devices - Historical Discussion of Hazards.” AIAA 2007-5468. In *AIAA/ASME/SAE/ASEE Joint Propulsion Conference & Exhibit*, 8–11 July, Cinncinnati, OH. Reston, VA: American Institute of Aeronautics and Astronautics. https://doi.org/10.2514/6.2007-5468.

vor dem Esche, R. 2016. *Safety of Flywheel Storage Systems*. Jülich, Germany: Stornetic GmbH. http://dx.doi.org/10.13140/RG.2.2.12482.99524.

Walter, M. G., E. L. Warren, J. R. McKone, S. W. Boettcher, Q. Mi, E. A. Santori, and N. S. Lewis. 2010. “Solar Water Splitting Cells.” *Chemical Reviews* 110 (11): 6446–6473. https://doi.org/10.1021/cr1002326.

Ward, C. 2011. *UltraBattery*. CISROpedia. Accessed 6 March 2020. https://csiropedia.csiro.au/ultrabattery/.

White, M. K., S. M. Lux, J. L. Knight, M. J. Binder, F. H. Holcomb, and N. M. Josefik. 2005. *DOD Residential Proton Exchange Membrane (PEM) Fuel Cell Demonstration Program*. ERDC/CERL TR-05-22. Champaign. IL: U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory. http://hdl.handle.net/11681/20116.

Widera, B. 2020. "Renewable Hydrogen Implementations for Combined Energy Storage, Transportation and Stationary Applications." *Thermal Science and Engineering Progress* 16 (May): 100460. https://doi.org/10.1016/j.tsep.2019.100460.

Xie, C, Y Li, Y Ding, and J Radcliffe. 2019. "Evaluating Levelized Cost of Storage (LCOS) Based on Price Arbitrage Operations: With Liquid Air Energy Storage (LAES) as an Example." *Energy Procedia* 158 (February): 4852–4860. https://doi.org/10.1016/j.egypro.2019.01.708.

Yang, M., and J. Hou. 2012. "Membranes in Lithium Ion Batteries." *Membranes* 2 (3): 367–383. https://doi.org/10.3390/membranes2030367.

Your Weather Service. 2021. "Monthly Climate Sparta—Wisconsin." U.S. Climate Data. Accessed 8 June 2021. https://www.usclimatedata.com/climate/sparta/wisconsin/united-states/uswi0649.

Zeng, K., and D. Zhang. 2010. "Recent Progress in Alkaline Water Electrolysis for Hydrogen Production and Applications." *Progress in Energy and Combustion Science* 36 (3): 307–326. https://doi.org/10.1016/j.pecs.2009.11.002.

Zhan, Z., H. Zhao, P. C. Sui, P. Jiang, M. Pan, and N. Djilali. 2018. "Numerical Analysis of Ice-Induced Stresses in the Membrane Electrode Assembly of a PEM Fuel Cell under Sub-Freezing Operating Conditions." *International Journal of Hydrogen Energy* 43 (9): 4563–4582. https://doi.org/10.1016/j.ijhydene.2018.01.064.

Zhu, J., H. Zhang, W. Yuan, M. Zhang, and X. Lai. 2015. "Materials Insights into Low-Temperature Performances of Lithium-Ion Batteries." *Journal of Power Sources* 300 (December): 29–40.

———. 2013. "Design and Cost Estimation of Superconducting Magnetic Energy Storage (SMES) Systems for Power Grids." In *IEEE Power & Energy Society General Meeting*, 21–25 July, Vancouver, British Columbia, Canada. Piscataway, NJ: Institute of Electrical and Electronic Engineers. https://doi.org/10.1109/PESMG.2013.6672556.

Appendix A: Energy Storage Analysis Data Requirements Questionnaire

The project team developed this questionnaire with input from the U.S. Department of Energy's Energy Storage Program. This questionnaire seeks general information needed to perform techno-economic evaluations for energy storage options. Each project is unique, so information requested may be adjusted on a case-by-case basis.

1. **Energy storage system (ESS) objectives:** ESSs can be integrated into installation energy systems and planning in different applications but is often constrained by existing system components, contractual agreements, or regulatory requirements:
    a. Example applications for which an ESS could be evaluated:
        i. Peak shaving
        ii. Energy resiliency
        iii. Integration of renewable/clean/local energy sources
        iv. Remote power system
    b. Example system limitations that could constrain an EES:
        i. Transmission capacity limits
        ii. System configuration requirements (e.g., AC/DC tied to PV, 100 kW or less of PV per facility, etc.)
        iii. Interconnection requirements (e.g., no reverse power flow, restricted from performing arbitrage, etc.)
2. **Economic objective:** Investment in ESSs can be at different levels, depending on the need or available financial resources. Understanding the financial objectives of the installation and related funding constraints can help narrow the field of ESS options and integration approaches. The following are some factors to consider:
    a. Cost savings (e.g., peak shaving and net metering)
    b. Desired payback period
    c. Project funding options/limitations
3. **Technical evaluation needs or facility energy load needs:** Matching the facility need to an appropriate and reliable ESS technology is important to ensure the suitability of the match in the environment in which the ESS is expected to support the installation's mission. To inform this assessment, the following information is useful to understand how much electricity the ESS needs to provide:

   a. Minimum 1-year load/generation profiles for system being impacted by ESS. While hourly measurements provide better visibility into the load profile, at least monthly data is needed to understand any seasonal variability.
   b. Transformer sizes to all loads that need to be served by the ESS (kVA)
   c. Load data for the facilities that will connect to the ESS (kW, KWh), such as the following:
      i. Electrical
      ii. Air conditioning
      iii. Refrigeration
      iv. Space heating
      v. Water heating
4. **Utility Bills or Energy Costs:** Financial implications of integrating ESS are typically evaluated in comparison with or informed by the terms of utility bills and any related costs or savings. The following data sources are informative:
   a. Terms of any applicable utility tariffs*
   b. Terms of any applicable compensation structures (e.g., net metering agreements, tax credits for renewable/clean energy use, and demand response program participation)
   c. Market rates of electricity supply
   d. Utility bills with documented rate structure (e.g., peak/off-peak, demand charges, capacity charges, and transmission charges)
5. **Installation infrastructure:** System components, their location, their configuration, and their condition are important data to consider when integrating new ESSs:
   a. Up-to-date as-built infrastructure diagrams (e.g., electrical one-line diagrams)
   b. GIS-based infrastructure maps showing the location and connectivity of existing energy infrastructure and facilities on the installation
   c. Any system information about existing microgrid configurations or future interest in microgrid integration
   d. Existing monitoring, control, and cybersecurity systems and any applicable requirements
   e. Installation electricity outages, whether originating from the installation or the supplier

* A utility tariff is a pricing structure that an energy provider charges a customer for energy usage.

6. **Critical infrastructure:**[*] If an ESS is going to provide electricity to mission-critical infrastructure or facilities, the following information is helpful:
    a. Identified critical infrastructure or facilities
    b. Load data for critical infrastructure or facilities
    c. Outage history for the critical infrastructure or facilities
    d. Resilience requirements for the critical infrastructure or facilities
7. **On-site generation:** Some installations have existing or planned on-site generation available to contribute toward meeting the installation's electricity demand. Information about available generation sources, their capacity, and availability can be helpful when ESSs will be integrated with these generation sources:
    a. Existing renewable energy information
        i. Type of renewable (e.g., photovoltaic, wind, or biomass)
        ii. Design capacity of the renewable system
        iii. Generation profile (e.g., hourly/monthly data showing how much electricity is produced/consumed)
    b. Existing backup electricity supplies that would be available during an electricity supply disruption
        i. Energy supply (e.g., oil, gas, diesel, or battery)
        ii. Alternative supply from electricity provider
        iii. Capacity of energy supplies, efficiency of generators/systems, lifecycle performance expectations, and operating constraints
8. **Grid connectivity:** If the ESS will be part of a grid-connected system, it is important to understand the system and the limits that it may place on any interconnectivity of the ESS and existing electricity system infrastructure, whether those limits restrict, for example, capacity, location, or time of use. Relevant information can come from the following:
    a. Local utility infrastructure location and capacity limits
    b. Interconnection requirements imposed by the local utility, the local system operator, or local utility regulators/energy policies

[*] Critical infrastructure information may have distribution limitations and require a secure means of sharing, analyzing, and documenting the information and findings. The case studies in this report did not specifically address critical infrastructure; however, it's important to recognize that it should be included, as appropriate, in any ESS analysis when investigating the appropriate ESS to meet the critical-infrastructure need.

c. ESS integration configuration restrictions (e.g., solar + battery systems may not be permitted as grid-connected so that the system operator has better control over the system electricity flows)

9. **Skilled personnel on-site for installation/management:** Capable operators are key to any installation system, including on-site EESs. Such personnel should be appropriately trained to monitor and react to any disruptions to activate or ensure automatic activation of an ESS to mitigate against the disruption. Similarly, like many other system, planning, exercises, and safety protocols are paramount to ensure the installation can effectively and efficiently benefit from integration of ESSs and can provide input to their future integration designs. If personnel are more capable of managing one type of ESS, considering the training needs of the staff to operate and manage a different type of ESS should not be overlooked as part of the determination about investment in ESSs.

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing this collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to Department of Defense, Washington Headquarters Services, Directorate for Information Operations and Reports (0704-0188), 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302. Respondents should be aware that notwithstanding any other provision of law, no person shall be subject to any penalty for failing to comply with a collection of information if it does not display a currently valid OMB control number. PLEASE DO NOT RETURN YOUR FORM TO THE ABOVE ADDRESS.

1. REPORT DATE (DD-MM-YYYY)	2. REPORT TYPE	3. DATES COVERED (From - To)
09/01/2021	Final Report	FY19–FY21

4. TITLE AND SUBTITLE
Installation Resilience in Cold Regions Using Energy Storage Systems

5a. CONTRACT NUMBER

5b. GRANT NUMBER

5c. PROGRAM ELEMENT
131079

6. AUTHOR(S)
Caitlin A. Callaghan, Danielle R. Peterson, Timothy J. Cooke, Brandon K. Booker, and Kathryn P. Trubac

5d. PROJECT NUMBER
A10

5e. TASK NUMBER

5f. WORK UNIT NUMBER

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
U.S. Army Engineer Research and Development Center (ERDC)
Cold Regions Research and Engineering Laboratory (CRREL)
72 Lyme Road
Hanover, NH 03755-1290

8. PERFORMING ORGANIZATION REPORT NUMBER
ERDC/CRREL TR-21-13

9. SPONSORING / MONITORING AGENCY NAME(S) AND ADDRESS(ES)
Headquarters, U.S. Army Corps of Engineers
Washington, DC 20314-1000

10. SPONSOR/MONITOR'S ACRONYM(S)
USACE

11. SPONSOR/MONITOR'S REPORT NUMBER(S)

12. DISTRIBUTION / AVAILABILITY STATEMENT
Approved for public release; distribution is unlimited.

13. SUPPLEMENTARY NOTES

14. ABSTRACT
Electrical energy storage (EES) has emerged as a key enabler for access to electricity in remote environments and in those environments where other external factors challenge access to reliable electricity. In cold climates, energy storage technologies face challenging conditions that can inhibit their performance and utility to provide electricity. Use of available energy storage technologies has the potential to improve Army installation resilience by providing more consistent and reliable power to critical infrastructure and, potentially, to broader infrastructure and operations. Sustainable power, whether for long durations under normal operating conditions or for enhancing operational resilience, improves an installation's ability to maintain continuity of operations for both on- and off-installation missions. Therefore, this work assesses the maturity of energy storage technologies to provide energy stability for Army installations in cold regions, especially to meet critical power demands. The information summarized in this technical report provides a reference for considering various energy storage technologies to support specific applications at Army installations, especially those installations in cold regions.

15. SUBJECT TERMS
Cold regions, Electric power, Energy storage, United States--Army--Facilities

16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT	b. ABSTRACT	c. THIS PAGE			19b. TELEPHONE NUMBER (include area code)
Unclassified	Unclassified	Unclassified	SAR	115	