ARMY NET ZERO

Guide to Renewable Energy Conservation Investment Program (ECIP) Projects

June 2015

DISCLAIMER

ACKNOWLEDGMENTS

This report was written by Jesse Dean, Kate Anderson, Robi Robichaud, Michael Hillesheim, Randolph Hunsberger, and Samuel Booth of the National Renewable Energy Laboratory (NREL). This work is sponsored by the U.S. Army, Assistant Secretary of the Army (Installations, Energy & Environment) and the Department of Energy's (DOE's) Federal Energy Management Program (FEMP). It is part of the Army's Net Zero pilot program and builds on past Net Zero Energy work sponsored by FEMP and supported by NREL. NREL gratefully acknowledges the assistance of Paul Volkman at the Office of the Assistant Secretary of the Army (Installations, Energy & Environment), Karen Moore, Bob Hennessee, and Steve Lambert at the U.S. Army Corps of Engineers Engineering and Support Center, Huntsville, Bill Stein at the U.S. Army Engineer Research and Development Center Construction Engineering Research Laboratory (ERDC-CERL), Coby Jones at Fort Bragg, Janice Lauletta and Thomas Sessa at the New York District Army Corps of Engineers, and Army energy managers Scott Clark, Todd Dirmeyer, Jay Tulley, and Nick Stecky. The authors also thank Andy Walker, Alicen Kandt, Lars Lisell, Jessica Katz, Otto Van Geet, Ted James, Ran Fu, Donald Chung, Heidi Blakley, and Devonie McCamey at NREL.

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Front page images (top, left to right, bottom): Photo from U.S. Army, Fort Knox; photo from U.S. Army 79867; photo from Sgt Brett Miller, U.S. Army 2012_0623; photo from John Prettyman, U.S. Army 899842

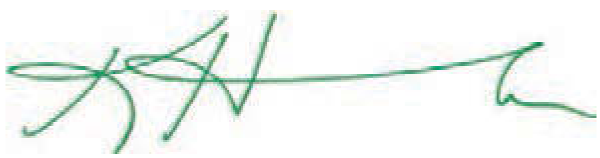
MESSAGE FROM HONORABLE KATHERINE HAMMACK

Photo from U.S. Army 291555

In October 2010, I announced the creation of the Army Net Zero Initiative. Net Zero is a holistic strategy founded upon long-standing sustainable practices and incorporates emerging best practices to manage energy, water, and waste at Army installations. The intent of the Net Zero Initiative is to enhance mission effectiveness and increase installation resiliency. Additional energy-related Federal mandates—including Executive Order 13514, the Energy Policy Act of 2005, and the Energy Independence and Security Act of 2007—further support Net Zero strategies.

The Energy Conservation and Investment Program (ECIP) is a critical element of the Department of Defense's strategy to improve the energy performance of its fixed installations. ECIP supports the Army Net Zero Initiative by funding holistic projects that dramatically change the energy consumption at an installation, integrate multiple renewable energy technologies to realize synergistic benefits, and implement a documented energy plan. Executing energy efficiency and renewable energy projects through ECIP is a key strategy for installations trying to reach Net Zero. This guide provides information to help installations prepare renewable energy ECIP applications and obtain funding for projects that advance them toward Net Zero.

I am amazed at the progress Army installations have already made to reduce energy and water consumption as well as waste generation. We will all monitor the journey these installations embark on to reach the final Net Zero goal.



Honorable Katherine Hammack
Assistant Secretary of the Army
(Installations, Energy & Environment)
Washington, DC

EXECUTIVE SUMMARY

This guide is intended to serve as a desk reference for energy managers at Army installations who are preparing renewable energy (RE) Energy Conservation Investment Program (ECIP) applications. This guide provides practical information on six RE technologies and walks the energy manager through the process of creating a technically and financially sound RE ECIP application. Techno-economic guidance is provided on solar photovoltaic (PV), solar hot water (SHW), solar ventilation preheating (SVP), ground source heat pump (GSHP), biomass, and wind technologies. Example calculations and links to technology-specific trainings, software tools, and references are provided in each section. This information is intended to supplement the existing ECIP guidance document that is released by the Assistant Chief of Staff for Installation Management (ACSIM) each year.[1]

Several common factors for success are shared by the RE ECIP projects that are awarded each year. First, they are economically viable due to high utility energy costs, good incentives, and/or good RE resources. Second, each project contributes to the installation's and the Army's RE goals, and often has a synergistic effect where it integrates with other projects to meet a larger overall goal or vision for the installation. Successful ECIP projects are typically well aligned with Army priorities. Third, the project is put forward by a qualified team that submits a thorough and accurate application, with strong management buy-in and commitment. Partnering with other federal agencies and capitalizing on new and innovative technologies are also factors for success.

The following tables, organized by technology, summarize key information needed for ECIP applications. More information on each item in the table is provided in the detailed technology sections of this guide.

[1] Army (2014). *Energy Conservation Investment Program Annual Guidance.* Army Assistant Chief of Staff for Installation Management. (internal only).

Photovoltaics	
Technology Description	Photovoltaics (PV) are semiconductor devices that convert sunlight directly into electricity. The primary components are the PV array and the inverter. Rooftops, carports, and ground-mounted arrays are common mounting locations.
Capital Costs	$2.54–$3.90/watt (W), varies by size; for more information, see: http://www.nrel.gov/docs/fy14osti/62558.pdf and http://www.nrel.gov/analysis/tech_cost_dg.html.
Operations and Maintenance (O&M) Costs	Recurring: $12.50/direct current (DC)-kilowatt (kW) annual O&M for fixed-axis systems, $20/DC-kW annual O&M for single-axis tracking (SAT) systems. Non-recurring: $0.10/W for one-time inverter replacement in year 15 (fixed-axis and SAT).
Incentives Interconnection Limit Net Metering Policy	Varies by state and utility. For more information, see: http://www.dsireusa.org/.
2013 Discount Factors	See the Annual Supplement to Handbook 135: http://energy.gov/eere/femp/building-life-cycle-cost-programs. Annual energy savings: Varies by census region. See Table Ba-1 through 4. One-time inverter replacement: 0.744 (Table A-1). Annual O&M: 17.41 (Table A-2).
Analysis Period	25 years.
Tools and Resources for Estimating Energy Savings	PVWatts: http://pvwatts.nrel.gov. RETScreen: http://www.retscreen.net. Solar Advisor Model: https://sam.nrel.gov.
Training	*Selecting, Implementing, and Funding Photovoltaic Systems in Federal Facilities:* http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=140.
Army Installations with ECIP PV Projects	Fort Hunter Liggett: todd.a.dirmeyer.civ@mail.mil. Presidio of Monterey: jay.h.tulley.civ@mail.mil.
Project Development Considerations	Siting *Mission Impact*: Design to avoid potential glint and glare around airports. *Orientation and Tilt*: Face PV arrays south (in northern hemisphere) with a tilt angle ranging from 0° to an angle equal to site latitude. *Shading*: Avoid locations where panels will be shaded between 9 a.m. and 3 p.m. *Setbacks*: Locate rooftop PV systems at least 2–6 feet (ft) from the roof edge. *Historic Buildings*: Consult the historic preservation office. Arrays generally should not be visible from the street on historic buildings. *Building Structural Integrity:* PV systems add a dead load of 3–6 pounds (lb)/ft^2. Avoid rooftops that cannot support an additional load. *Roof Age and Condition*: Install rooftop systems on roofs with a useful life of at least 25 years. System Design *Equipment Selection*: The site does not need to specify equipment; the solar installer can select it based on the best value. *Electrical Interconnection and Power Factor Correction*: Determine where the system will tie into the local grid and whether step-up transformers will be required. Evaluate inverters with power factor correction capabilities. *Metering*: Advanced meters must be installed on all ECIP projects and connected to the meter data management system (MDMS). Estimating Savings *Demand Savings*: Estimate demand savings based on a model of hourly PV energy production and the installation's hourly load profile. *Equipment Lifetime*: PV panels last 25 years; inverters last 10–20 years. Policies and Permits Contact the local utility and privatized utility for interconnection procedures, net metering regulations, and local incentives.

Solar Hot Water	
Technology Description	SHW systems use solar collectors to capture sunlight to heat water. The primary components are the collector and storage tank.
Capital Costs	The average cost for a flat-plate SHW system is $141/ft^2, with a range of approximately $60–$220/ft^2; see: http://www.nrel.gov/analysis/tech_cost_dg.html.
O&M Costs	Recurring: 0.5%–1% of the initial installed cost.
Incentives **Interconnection Limit** **Net Metering Policy**	Varies by state and utility. For more information, see: http://www.dsireusa.org/.
2013 Discount Factors	See the Annual Supplement to Handbook 135: http://energy.gov/eere/femp/building-life-cycle-cost-programs. Annual energy savings: Varies by census region. See Table Ba-1 through 4. Annual O&M: 17.41 (Table A-2).
Analysis Period	25 years.
Tools and Resources for Estimating Energy Savings	RETScreen: http://www.retscreen.net. Solar Advisor Model: https://sam.nrel.gov.
Training	Introduction to Renewable Energy Technologies: http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=20. Distributed-Scale Renewable Energy Projects: From Planning to Project Closeout: http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=2188.
Army Installations with ECIP SHW Projects	Schofield Barracks: keith.k.yamanaka.civ@mail.mil.
Project Development Considerations	<u>Siting</u> *Domestic Hot Water (DHW) Fuel Source:* Target systems using electric resistance elements because of higher energy costs. *Facilities with Large Hot Water Load*: Target facilities with large hot water loads, such as barracks, laundry facilities, and kitchens. *Distributed Versus Centralized Hot Water Systems*: Target existing facilities with centralized DHW tanks. *SHW Versus PV with Heat Pump Water Heaters*: The combination of onsite PV systems and heat pump water heaters should be compared to a SHW system to ensure that a traditional SHW system is the most economical solution for the given application. *Orientation and Tilt*: Orient panels facing south and mounted with a tilt angle ranging from 0° to an angle equal to site latitude. *Shading*: Although shading should generally be avoided, SHW panels are less sensitive to shading than PV panels. *Historical Considerations*: Consult the historic preservation office. An array generally should not be visible from the street on historic buildings. *Building Structural Integrity*: Ensure the roof can handle an added dead load of 2–5.5 lb/ft^2. *Roof Age and Condition*: SHW systems should be installed on roofs that have a useful life of at least 25 years. <u>System Design</u> *Implement Efficiency First*: The existing DHW equipment should be analyzed prior to the installation of a SHW system, and all applicable water conservation and energy efficiency opportunities should be implemented prior to the sizing of an SHW system. *Equipment Selection*: The site does not need to specify certain SHW panels or storage tanks. The system should be sized based on the hot water load, and that information can be provided to solar installers when the project is competitively bid out. *Metering*: Advanced meters must be installed on all ECIP projects and connected to MDMS. <u>Policies and Permits</u> The site should contact the local utility to get a listing of any local incentives or policies regarding SHW installations.

Solar Ventilation Preheating	
Technology Description	SVP is a simple and efficient technology that uses solar radiation to preheat building ventilation air during the heating season. The primary components are the collector and ventilation fan.
Capital Costs	The average cost for a solar ventilation preheating system is $31/ft², with a range of approximately $16–$46/ft²; see: http://www.nrel.gov/analysis/tech_cost_dg.html.
O&M Costs	SVP systems typically require little to no annual maintenance; therefore for economic analysis, annual O&M costs are typically assumed to be $0.
Incentives **Interconnection Limit** **Net Metering Policy**	Varies by state and utility. For more information, see: http://www.dsireusa.org/.
2013 Discount Factors	See National Institute of Standards and Technology Handbook 135 and the Annual Supplement to Handbook 135: http://energy.gov/eere/femp/building-life-cycle-cost-programs. Annual energy savings: Varies by census region. See Table Ba-1 through 4.
Analysis Period	30 years.
Tools and Resources for Estimating Energy Savings	RETScreen: http://www.retscreen.net.
Training	Introduction to Renewable Energy Technologies: http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=20. Transpired Air Collectors Ventilation Preheating fact sheet: http://www.nrel.gov/docs/fy06osti/29913.pdf. Federal Technology Alert. Transpired Collectors (Solar Preheaters for Outdoor Ventilation Air): http://www1.eere.energy.gov/femp/pdfs/fta_trans_coll.pdf.
Army Installations with Successful ECIP SVP Projects	Fort Drum: stephen.e.rowley3.civ@mail.mil. Fort Carson: scott.b.clark.ctr@mail.mil.
Project Development Considerations	Siting *Climate Zone*: In traditional building heating applications, this technology should be applied to heating load-dominated climates. *Building Orientation*: Solar ventilation preheat systems should ideally be designed and installed in a position that faces within 45° of true south (for the northern hemisphere) to maximize solar energy collection. *Building Type*: Vehicle maintenance facilities and other industrial buildings that require a large amount of ventilation air and match well with the aesthetic of metal siding are ideal applications for this technology. *Heating System*: The total airflow rate through the heating system, outside air ventilation requirements, location of the outside air intake, and type of heating system all need to be recorded to determine installed costs and energy savings. *Exhaust Air Heat Recovery*: Existing facilities that already have exhaust air heat recovery should be avoided. *Internal Heat Gains*: A building that is not already heated by internal gains (for example, buildings with many computers or other equipment that give off heat and require year-round cooling) is preferred for this technology.

Ground Source Heat Pumps	
Technology Description	GSHP systems are a space heating and cooling technology that takes advantage of the relatively constant temperature of the ground to provide building space conditioning. The ground is a source of heat in the winter and an efficient heat rejection medium in the summer. The primary components are the heat pump, heating, ventilating, and air conditioning (HVAC) distribution system, and loop field (also called heat exchanger).
Capital Costs	For new construction, closed-loop GSHP system capital costs can range from $5,000 to $10,000 per ton (average $7,500/ton for the entire system). For a retrofit, the range is $7,000–$17,000 per ton (average $12,000/ton).
O&M Costs	Annual O&M costs for GSHP systems are estimated at $6-$8 per ton, which is about one-third that of conventional HVAC systems.
Incentives **Interconnection Limit** **Net Metering Policy**	Varies by state and utility. For more information, see: http://www.dsireusa.org/.
2013 Discount Factors	See the Annual Supplement to Handbook 135: http://energy.gov/eere/femp/building-life-cycle-cost-programs. Annual energy savings: Varies by census region. See Table Ba-1 through 4. Annual O&M: 17.41 (Table A-2).
Analysis Period	25 years.
Tools and Resources for Estimating Energy Savings	RETScreen: http://www.retscreen.net.
Training	Heat Spring webinars and training: https://www.heatspring.com/categories/geothermal-training-courses. Information and educational materials: • International Ground Source Heat Pump Association: http://www.igshpa.okstate.edu • GeoExchange: http://www.geoexchange.org/ • Ground Source Heat Pump: A Guide Book: http://www.erec.org/fileadmin/erec_docs/Projcet_Documents/RESTMAC/GSHP_brochure_v_2008.pdf.
Army Installations with Successful ECIP GSHP Projects	Ft. Knox: robert.d.dyrdek.civ@mail.mil. Ft. Bragg: joseph.c.jones4.ctr@mail.mil.
Project Development Considerations	<u>Siting</u> *Building Type and Usage:* Target packaged single zone (PSZ) HVAC systems for GSHP retrofits. *Climate*: Target buildings with more balanced heating and cooling loads for GSHP installations. *Hybrid Systems*: For heating or cooling dominated thermal loads, consider a hybridized system with an onsite boiler or cooling tower. *New Construction Versus Retrofit*: Installation in a new building is much less complex than retrofitting a GSHP into an existing building. *Mission Impact*: GSHP systems will have no impact on the mission, except possibly during construction (dust and noise). <u>System Design</u> *Building Thermal Load:* Use existing heating and cooling plant nameplate data and operational load to determine the GSHP size. *Loop Field Sizing*: The size of the loop field is a function of building thermal load and subsurface thermal parameters. These, coupled with land availability and site-specific regulations, inform the decision about loop field type and configuration. For horizontal heat exchangers (HEs), it is recommended that soil samples be collected at the proposed installation depth interval for analysis to determine relevant thermal parameters. If a vertical HE is being considered, drill a test borehole to an adequate depth and complete a thermal response test to determine the in-situ values of thermal parameters. *Horizontal Loop Fields*: Installing horizontal HEs requires the largest amount of land disturbance but typically does not require special permitting because of their shallow installation depth (<10 ft).

Ground Source Heat Pumps	
	Vertical Loop Fields: Due to space constraints in developed areas, vertical systems are a suitable alternative to horizontal systems. Borehole depth and diameter are dependent on subsurface thermal parameters and whether the loop is open or closed. *Open Versus Closed Loop*: Local, state, and/or federal regulations may constrain open loop installation, especially in areas where water resources are scarce or protected and in areas where contamination may be present. Open-loop HEs require more planning and permitting activities than closed-loop HEs, which require minimal permitting. *Surface Water:* A surface water HE should be placed at a depth to avoid seasonal water level fluctuations, diurnal and seasonal tidal variation, and/or watercraft traffic. Surface water installations also need to be installed at a depth where the water column temperature is relatively stable; this varies by water body type and local climate. *Equipment Monitoring*: Monitoring systems should be specified in the installation to ensure proper operation and energy production. *Controls*: Based on industry data, the primary reason a GSHP system may not work as expected is because of system controls. It is imperative that the GSHP system designer and installer be properly accredited with a proven record of successful installations. Policies and Permits Standard building HVAC and electrical permits are required for heat pumps and HVAC distribution systems. The type and complexity of permitting required for the loop field installation depends on its type (open or closed) and configuration, as well as local and state regulations. Local GSHP installers are usually the best source of information for determining permitting requirements.

Biomass Heating	
Technology Description	Biomass systems convert biomass feedstocks into heat and/or electricity. A typical biomass heating system includes fuel receiving, storage, and handling; a combustion system (and steam generator where applicable); and air pollution control equipment.
Capital Costs	\$60,000–\$100,000/million British thermal units (MMBtu)/hour for primary equipment. An additional 20%–30% for design, engineering, and shipping. Varies by size.
O&M Costs	Non-fuel: \$1–\$3 per MMBtu of heat delivered by the biomass system. Fuel cost: \$30–\$50 per green ton plus a delivery cost of 2.1 times the price of a gallon of diesel. For example, if diesel costs \$4/gallon, the delivery cost is approximately \$8.40/ton.
Incentives **Interconnection Limit** **Net Metering Policy**	Varies by state and utility. For more information, see: http://www.dsireusa.org/.
2013 Discount Factors	See the Annual Supplement to Handbook 135: http://energy.gov/eere/femp/building-life-cycle-cost-programs. Annual energy savings: Varies by census region. See Table Ba-1 through 4. Use rate for existing fuel-type biomass is offsetting. Annual O&M: 17.41 (Table A-2). Annual biomass fuel cost varies by census region. See Table Ba-1 through 4. Use the rate for distillate fuel.
Analysis Period	25 years.
Tools and Resources for Estimating Energy Savings	RETScreen estimates energy savings and economics: http://www.retscreen.net. NREL's Biofuels Atlas provides data on quantity of biomass resources in the region: http://maps.nrel.gov/biomass. The Wood Energy Calculator estimates energy content of biomass: http://www.southeastcleanenergy.org/resources/calculators.aspx.
Training	The National Training and Education Resource (NTER) DOE Office of Indian Energy Renewable Energy Curriculum includes a biomass module, available for free with registration at: https://www.nterlearning.org/web/guest/course-details?cid=405.
Army Installations with ECIP Biomass Projects	No Army installations are identified. Coast Guard Air Station Sitka: robert.c.deering@uscg.mil.
Project Development Considerations	<u>Siting</u> Centralized district heating systems (both hot water and steam) may be ideal candidates for biomass heating systems. *Space Requirements*: Fuel receiving, storage, and handling equipment requires additional space compared to fossil fuel systems. *Fuel Delivery and Truck Traffic:* Expect increased truck traffic and consider security issues associated with bringing offsite biomass fuel onsite. Biomass delivery trucks typically hold 20 tons of biomass with an energy content of about 220 MMBtu. <u>System Design</u> *System Sizing*: Size the system to meet 90% of annual load. A supplemental fossil fuel peaking system is typically needed. *System Integration*: Integration of the biomass boiler with a fossil fuel system requires careful engineering and controls design. *Biomass Fuel Sources*: Some fuel may be available on the installation, but typically some fuel must be sourced off-site. *Fuel Properties:* Moisture content typically ranges from 40% to 50%. Fuel with higher moisture content has less recoverable energy per pound. Wood cleanliness and chip size can significantly affect system reliability and maintenance. <u>Estimated Savings</u> *Maintenance*: Biomass systems require more maintenance than fossil systems. Sites commonly use a back-up fossil-fueled boiler. *Electric Energy and Demand Increase*: Due to the motors for running conveyance equipment and fans, biomass heating systems can increase electric power consumption and peak demand compared to a fossil fuel system. *Equipment Lifetime*: Biomass systems can operate for 40 years or more. For financial calculations, assume a 20- or 25-year lifetime. <u>Policies and Permits</u> The size and design of the plant, the method of steam generation, and local permitting requirements affect the permits required for a biomass heating plant. State agencies generally handle permitting.

Wind Turbines	
Technology Description	There are two major types of wind turbines that are named based on their orientation: vertical-axis wind turbines and horizontal-axis wind turbines (HAWTs). HAWTs are most common and range in size from as small as 400 W to as large as 5 megawatts (MW).
Capital Costs	$3,000–44,000/kW for projects in the size range of one to five utility-scale turbines. $5000–$8000/kW for 50- to 100-kW turbines.
O&M Costs	$35–$50/kW/year, depending on the number of turbines. O&M costs decrease on a $/kW basis for larger numbers of turbines.
Incentives **Interconnection Limit** **Net Metering Policy**	Varies by state and utility. For more information, see: http://www.dsireusa.org/.
2013 Discount Factors	See the Annual Supplement to Handbook 135: http://energy.gov/eere/femp/building-life-cycle-cost-programs. Annual energy savings: Varies by census region. See Table Ba-1 through 4. Annual O&M: 17.41 (Table A-2).
Analysis Period	25 years.
Tools and Resources for Estimating Energy Savings	RETScreen: http://www.retscreen.net. Solar Advisor Model: https://sam.nrel.gov. HOMER: http://homerenergy.com/HOMER_legacy.html. Radar and flight operation impacts: http://www1.eere.energy.gov/windandhydro/federalwindsiting/wind_siting_tools.html. Wind maps: http://www.windpoweringamerica.gov/wind_maps.asp.
Training	WINDExchange/DOE/NREL: http://apps2.eere.energy.gov/wind/windexchange/podcasts_webinar.asp. American Wind Energy Association (AWEA): http://www.awea.org/Events/Eventslist.aspx. Windustry: http://www.windustry.org/wind-basics.
Army Installations with Successful ECIP Projects	Camp Williams: ricy.jones.nfg@mail.mil. Tooele Army Depot: royal.d.rice.civ@mail.mil. Fort Buchanan: anibal.negron1.civ@mail.mil.
Project Development Considerations	Siting *Wind Power*: Wind power can be maximized by increasing tower height, siting wind turbines to avoid impediments (hills, trees, and buildings), and increasing the length of the rotor. Because of fluctuations in wind speed, wind turbines produce at full capacity only a fraction of the year. The typical capacity factor (CF) is 10%–25% for small wind turbines, and 30%–50% for utility-scale wind turbines. *Site Selection*: When siting a meteorological (met) tower, select the windiest buildable location that minimizes the distance to an electrical tie-in, has reasonable road surfaces for bringing in heavy equipment, and has room for cranes and a lay-down area for large turbines. *Mission Impact*: Military training grounds, radar, and telecommunication areas present siting challenges for wind turbines. Bring affected parties together early in the process to discuss potential impacts on flight paths, training grounds and activities, radar, etc. *Road Access*: For smaller turbines, road access is typically not an issue. For large wind turbines, adequate access for large wind turbine component shipments (tower sections and blades) and heavy construction equipment (cranes) needs to be fully investigated. *Wind Resource Assessment*: Wind resource needs to be assessed before building a wind turbine. The resource assessment approach used typically depends on the size and cost of the wind project. Projects between 1 kW and 50 kW can use maps and validated data. Any project larger than 50 kW should collect on-site data via a met tower for at least one year. *Proximity to Distribution/Transmission Line Interconnection:* Minimize the distance from the wind turbine to the point of interconnection. Estimated Savings *O&M*: Professional wind turbine maintenance contractors are recommended after the manufacturer warranty period ends. Policies and Permits Permits from radar regulating authorities, including DOD, Federal Aviation Administration, and next-generation radar (NEXRAD), are required. Local or Army base building permits and National Environmental Policy Act (NEPA) review are also required. There may be state agencies with permitting requirements, as well as transportation permits.

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INTRODUCTION

The Department of Defense (DOD) Energy Conservation Investment Program (ECIP) is a subset of a larger Military Construction (MILCON) program that provides, on average, approximately $150 million per year in funding to support the DOD's energy programs. Of the $150 million annual ECIP budget, approximately 25%, or $37.5 million, is planned to be used on renewable energy (RE) projects. The DOD has issued guidance that large-scale RE projects (generally greater than 2 MW) that are candidates for power purchase agreements or third-party financing should not be funded through the ECIP program. Thus, this guide focuses on the deployment of smaller-scale RE technologies that are smaller than 2 MW and are not currently candidates for third-party financing.

This guide is intended to serve as a desk reference for energy managers at Army installations who are preparing RE ECIP applications. This information is intended to supplement the existing ECIP guidance document that is released by the Assistant Chief of Staff for Installation Management (ACSIM) each year.[2] This guide provides practical information on six RE technologies and walks the energy manager through the process of creating a technically and financially sound RE ECIP application. Techno-economic guidance is provided on solar photovoltaic (PV), solar hot water (SHW), solar ventilation preheating (SVP), ground source heat pumps (GSHP), biomass, and wind technologies. Example calculations and links to technology-specific trainings, software tools, and references are provided in each section. A list of potentially cost-effective PV, SHW, SVP, biomass, and wind projects at 87 Army installations is provided in Appendix C. This list is based on a preliminary screening conducted by NREL and may be considered for further analysis to determine whether they are potentially viable ECIP projects.

[2] Army (2014). *Energy Conservation Investment Program Annual Guidance.* Army Assistant Chief of Staff for Installation Management. (internal only).

CRITERIA FOR A SUCCESSFUL ECIP APPLICATION

ECIP Scoring Process

The 'Energy Conservation Investment Program Annual Guidance' document outlines the evaluation criteria that are used to rank each RE application. RE projects must have a savings to investment ratio (SIR) greater than 1, and the overall program must achieve an SIR greater than 2. The minimum project cost is $750,000, and projects over $2,000,000 are line-item approved by Congress. In addition to the standard project development considerations and techno-economic considerations, ECIP submissions are also weighted by the project's contributions to the agency's goals, its synergistic effect with other technologies, the level of innovation, and the project's service mission. Table 1 outlines the categories that are scored for each submission (based on draft OSD FY 2016 guidance) in order of precedence.

Table 1. FY 2015 RE ECIP Selection Criteria

Criteria	Description
Net Present Value	Calculated using SIR and simple payback
Service Priority	Project ranking among all ECIP projects submitted by a service
Benefit to Investment Ratio	A measure of the energy savings or generation per dollar invested
Energy Plan	Degree to which the projects are part of a documented installation, region, department or component energy plan
Test Bed Application	Degree to which projects implement a demonstrated test bed technology or other innovative technology
Synergistic Effect	Degree to which projects integrate multiple technologies to realize synergistic benefits
Goals	Degree to which projects contribute to their installations annual energy goals

General best practices associated with the evaluation criteria in the ECIP application are provided below:

- **Service Priority:** A project that is a priority for a given service will score higher than a project that is not a priority for the service. If the service is focused on installing as much onsite PV or wind as possible, these might receive a higher service priority than a biomass heating project that offsets natural gas consumption, for example. The site is encouraged to work with their respective service representatives to ensure that the given project is a service priority.

- **Energy Plan:** The site should provide evidence that the project is included in a documented energy plan at the installation, region, department, or component level. This demonstrates that the project is part of a coordinated energy strategy.

- **Test Bed Application:** New and innovative technology applications score higher than standard technology applications. For example, technologies proven through the Environmental Security Technology Certification Program (ESTCP) that are selected for implementation through an ECIP project would score well for this evaluation criterion.

- **Synergistic Effect:** The site should describe how this technology fits into the overall energy efficiency, RE, and microgrid strategy for the base. The technology should fit into a larger goal of integrating various technologies to reduce energy, produce onsite RE, and enhance energy security. A PV system that will complement a planned battery storage and microgrid installation, for example, will score higher than a standalone PV system.

- **Goals:** The site should describe how the given application contributes to both the installation's RE goals and the larger service's RE goals. If the site has a Net Zero Energy goal or a more progressive RE goal, the project's contribution to this goal should also be articulated in the ECIP form.

Additional best practices associated with past experience reviewing and submitting RE ECIP applications are provided below:

- **Management buy-in:** Securing management buy-in and commitment to the project is critical to the project's success and needs to occur before a given project is fully scoped out.

- **Team:** A qualified team of supportive stakeholders including the energy manager, installation commander, site planner, environmental representative, contracting officer, and utility representative will increase chances of project success. Bringing in qualified energy analysts and renewable energy experts as advisors to ensure that the project is analyzed correctly can also strengthen the project.

Project Development Considerations

The first step in creating a successful ECIP application is to understand the various project development considerations that need to be addressed. A successful RE ECIP application will show that key project development factors have been addressed, indicating chances of project success are high and that ECIP should invest in the given project.

The RE project development process is described in the "Army Guide: Developing Renewable Energy Projects by Leveraging the Private Sector".[3] Though this guide focuses on third party-financed projects rather than Army-owned projects, the steps described for conducting early stage due diligence to minimize project development risk for the Army apply to ECIP projects as well. Minimizing development risk increases the projects chance of success because it is well aligned to the goals of ECIP, meets ECIP economic criteria, has no obvious policy barriers (such as exceeding utility interconnection limits or violating environmental regulations), is technically viable, and has buy-in of all stakeholders.

During early project development, project value to meet the ECIP criteria is identified by the existence of an economically feasible project with a cost-effective and available site, access to a viable renewable resource, and installation off-take requirements. Mitigating excessive risk is critical to long-term project success. These are the first indicators of value and are used for early screening:

- ***Site.*** A site for the project should be identified. The site should be physically viable (in terms of slope, vegetation, soil conditions, infrastructure, access, etc.), require minimal site-specific development costs, and be acceptable to all stakeholders in the context of site planning, highest and best use, conflicting or competitive uses for the land, and mission impact. For technologies mounted on buildings, structural integration and historic preservation rules need to be considered. A site development plan signed off by all stakeholders strengthens an ECIP application.

- ***Resource.*** The availability and quality of the renewable resource being considered for the project needs to be characterized and understood to estimate energy production. Different technologies require different levels of characterization. For solar, hourly or monthly solar datasets available in RE screening tools and resource maps are likely sufficient; for wind, 12 months of onsite measurements are needed.

[3] *Army Guide: Developing Renewable Energy Projects by Leveraging the Private Sector*. (2014). U.S. Army Office of Energy Initiatives. Accessed March 2015: http://www.asaie.army.mil/Public/ES/oei/docs/2014%2011%2006%20Army%20Guide%20to%20Developing%20Renewable%20Energy%20Projects.pdf.

Once it is decided to move forward with a project, the eight assessment criteria are used when gathering and assessing data to identify major project constraints and determine mitigation strategies while maintaining viable project value and economics. The eight assessment criteria of project development are as follows:

- ***Mission and Energy Security.*** Project goals and objectives are established and then constantly reevaluated along with any effects of the project on installation mission and energy security as part of this risk criterion. An excessive risk can exist if a project adversely affects the Army or installation mission, or fails to meet established goals and objectives**.**

- ***Economics.*** The ECIP program requires cost effective renewable energy projects. Projects must demonstrate savings within the program's requirements by evaluating utility rates, capital investment costs, operations and maintenance costs, incentives, and other non-energy cost savings.

- ***Real Estate.*** Site selection affects installation real estate and must be coordinated with mission requirements, master planning, public works, electrical, transportation, and other infrastructure. Once a site is identified, potential aviation impact should be analyzed per DOD Siting Clearinghouse[4] for height regulations, as well as glint and glare potential for solar considerations.[5]

- ***Regulatory and Legal.*** Research the regulatory environment of the state or region in which the project is located to ensure that the project does not exceed any legal or policy limitations on construction, operations, or contracting. These can include interconnection and net metering limits and requirements for emissions and plant sizing.

- ***Offtake.*** Energy generated by most ECIP projects will be consumed onsite, so typically there is no contract required for purchase of the energy. Interconnection agreements with the utility and any limits these might impose on the system design must be understood.

- ***Technical/ Integration.*** All the technical requirements to connect to the grid and any thermal loads should be identified. At the ECIP application stage, a preliminary design should be completed to show system type, size, location, general configuration, and an understanding of how the system will be technically interconnected to the grid. Technical considerations necessary to achieve energy security goals should be defined. Coordination with and by installation staff with privatized utility providers and local serving utilities is recommended. Detailed design and construction documents are typically developed after the ECIP award.

- ***Environmental.*** It is important to understand all permits necessary for project construction and operation, including all federal requirements related to environmental regulations in the National Environmental Policy Act's (NEPA) Environmental Assessment (EA) or Environmental Impact Study requirements. NEPA permitting can add significant time to the RE project development process, so this should be started early. A site-wide EA that covers all potential RE development can efficiently address the NEPA requirement.

- ***Procurement.*** With all the other elements in place, a successful ECIP application will secure the capital needed to fund the final development, construction, and commissioning of the project.

[4] Part 211 of Title 32, Code of Federal Regulations "Mission Compatibility Evaluation Process" establishes procedures for review by DOD of applications submitted to the Federal Aviation Administration relating to potential air obstructions.

[5] Memorandum, DUSD (I&E), 11 Jun 2014, subject: Glint/Glare Issues on or near Department of Defense (DOD) Aviation Operations.

ESTIMATING COSTS AND SAVINGS

An ECIP application requires identifying RE project costs and savings including upfront investment costs, projected energy savings, and recurring and non-recurring non-energy costs or savings. The investment cost is made up of the construction cost, plus supervision, inspection, and overhead (SIOH) and design costs that are calculated as a fixed percent of the construction cost for RE ECIP projects. Equipment salvage value and any utility rebates are subtracted to arrive at the total investment cost. Recurring energy savings are estimated based on anticipated reductions in utility bills. Recurring non-energy costs and savings are made up of annual O&M costs, minus any recurring incentives. Non-recurring non-energy costs and savings are made up of interconnection fees, one-time O&M costs (such as PV inverter replacement), minus any one-time future incentives. The following sections provide guidance on how to estimate these RE project costs and savings.

Investment Costs

RE installation costs are dynamic and change from year to year and from location to location. PV costs, for example, have dropped significantly over the last few years, and historic costs are typically not sufficient to estimate future installed costs. This guide focuses on the use of up-to-date installed costs from reputable sources as a means of estimating installed costs.

Estimating the construction cost can be challenging at the application stage. The best way to accurately estimate costs is to get quotes from a developer or develop an engineering estimate; however, the energy manager may not be able to request quotes due to procurement regulations, and funding for a detailed engineering estimate may not be available. In this case, it is possible to estimate costs within +/- 30% using reputable cost data from the following resources:

- **National Renewable Energy Laboratory (NREL) Energy Technology Cost and Performance Data for Distributed Generation**.[6] Sponsored by the U.S. Department of Energy (DOE) Federal Energy Management Program (FEMP), this website provides a compilation of available national-level cost data from a variety of sources. While costs will vary by specific location, this database shows the mean installed cost as well as one standard deviation from the mean, for PV, wind, biomass, SHW, and GSHPs. Figure 1 shows an example of the 2013 cost data for PV, wind, and biomass**.**

[6] NREL Energy Technology Cost and Performance Data for Distributed Generation. Accessed March 2015: http://www.nrel.gov/analysis/tech_cost_data.html.

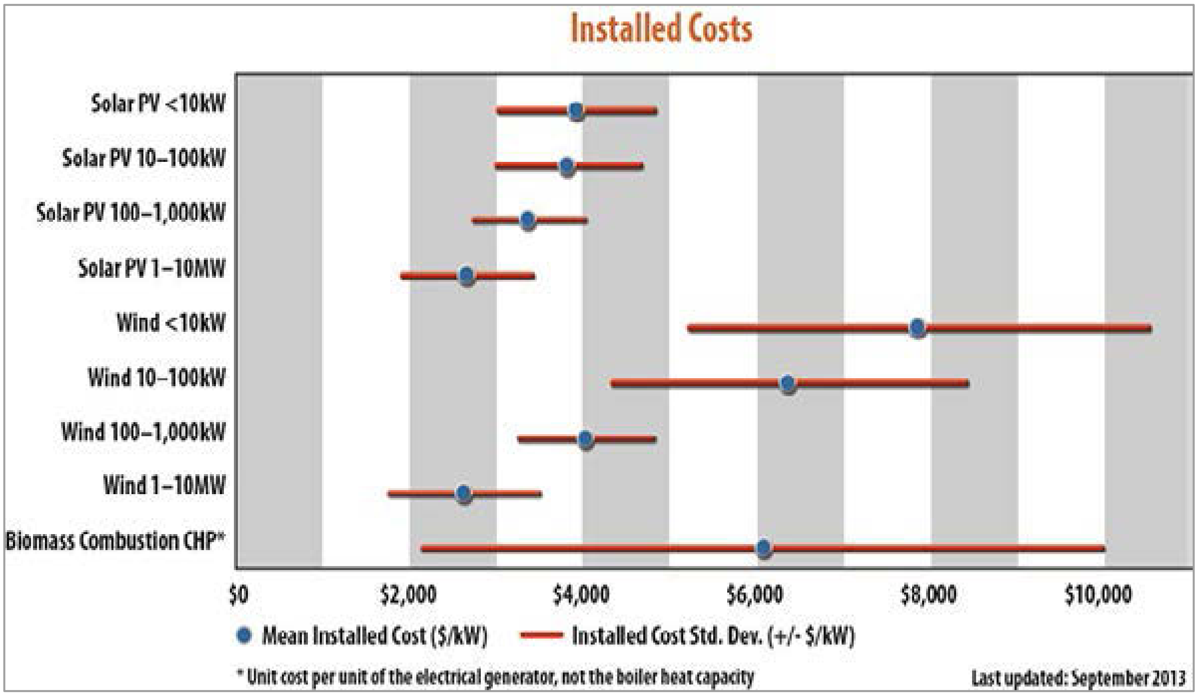

Figure 1. Example of installed cost data

Source: Energy technology cost and performance data for distributed generation website

- **Technology experts**. The US Army Corps of Engineers and NREL experts are often involved in project development at other installations and may be able to provide recent cost data from other similar projects.
- **Other DOD installations**. If nearby installations are developing RE projects, they may have recent quotes (within the last 6–12 months) that can inform RE project cost estimates.
- **State reports**. Some states, including California, New Jersey, and Massachusetts publish solar prices for systems that receive funding through their incentive programs.[7] One caveat on these reports is that they are often based on systems quoted well prior to the installation and connection date, and therefore may not be a good reflection of current prices.
- **Industry reports**. Industry groups often publish research reports with cost data on RE systems. Examples include the Solar Energy Industries Association (SEIA), Greentech Media, PV News, and Bloomberg New Energy Finance. There may be a fee for these reports. The Open PV Project[8] is a freely available database of PV installation data for the United States. Data for the projects are voluntarily contributed from a variety of sources including utilities, installers, and the general public. The data collected are actively maintained by the contributors and are always changing to provide an evolving, up-to-date snapshot of the U.S. solar power market.

[7] Go Solar California: http://www.californiasolarstatistics.ca.gov.

[8] Open PV: https://openpv.nrel.gov/.

If cost estimates are based on national- or state-level data, energy managers should consider increasing costs by approximately 10% to account for the higher project development costs often incurred at federal sites. RE project development costs at federal sites are often higher than at commercial sites for a variety of reasons, including the requirement to pay higher Davis-Bacon wage rates, increased safety regulations, more complex contracting requirements, and additional permitting requirements.

Once construction cost estimates are entered in the ECIP application, SIOH and design costs are automatically calculated as a fixed percent of the construction cost (5.7% and 4.0%, respectively). However, most of the quoted prices for RE have design costs already included in them, so energy managers should consider removing the additional 4% design cost for their project or reducing the construction cost estimate by 4% so that design costs are not counted twice. Estimated salvage value and utility rebates are then subtracted to arrive at the total investment cost. For most RE projects, salvage value at the end of the 25-year lifecycle will be $0. Information on identifying and estimating utility rebates is provided below in the Incentives section.

Energy Savings

Energy Usage Data and Utility Bills

The first step in calculating the potential savings from a renewable energy project is collecting historic energy usage data, utility bills, and understanding the current utility rate structures. Historic energy usage data and utility bills are typically provided in facilities reports by the resource management department or by the public works department. If the project is offsetting electricity use, then the site needs to gather electricity bills, and if the project is offsetting natural gas consumption, then the site needs to gather natural gas bills.

Electricity rate structures are typically more complex than natural gas rate structures. Electricity rate structures may be made up of fixed fees, demand charges, energy charges, and power factor costs. An explanation of common types of charges on an electric bill is provided in Appendix A. For initial estimates of energy savings, sites may use the blended rate. The blended rate is the total annual utility bill (in $) divided by the total annual energy consumption (in kWh). All utility charges, including fixed fees, demand charges, and energy rates, are rolled into one blended rate.

If the project looks economically viable or close to viable using the blended rate, sites should consider doing a more detailed analysis, where fixed fees and demand charges are separated from the energy charges. This more detailed analysis can benefit or hinder project economics, depending on the circumstances. For example, time-of-use pricing structures where the highest prices align well with solar production hours may benefit PV project economics. On the other hand, rate tariffs that have high demand charges as a percentage of their blended rate may harm PV project economics, because PV may not consistently reduce demand due to cloudy days or high demand hours that occur in the evening when PV production is lower. More detailed rate analyses can be complicated; sites should solicit help from the Army Corps of Engineers, national labs, or other experts if needed. Natural gas rate structures are typically simpler, consisting of a meter fee and a flat natural gas rate that is subject to change over the course of the year.

Estimating Annual Energy Savings

Once the electricity and natural gas rate structures are understood and the site has collected monthly utility bills, then they have enough information to size the RE system and calculate cost savings. Estimating the energy production and resulting energy cost savings from an RE system typically requires RE software tools specific to each technology. Information on applicable tools and example calculations are provided in the technology-specific example calculations. An explanation of typical rate structures is provided in Appendix A.

Conversion Factors

Conversion factors are typically required to convert electricity and steam energy production numbers into the format required by the ECIP form. A number of common conversion factors are provided in Table 2, and specific applications of various conversions are provided in the technology-specific example calculations.

Table 2. Energy Conversion Factors

Commodity	Conversion
Purchased Electricity	3,412 Btu/kWh
Purchased Steam	1,000 Btu/lb
Distillate Fuel Oil	138,700 Btu/gal
Natural Gas	1,031 Btu/ft^3
LPG, Propane, Butane	91,960 Btu/gal
Butane	102,032 Btu/gal
Bituminous Coal	24,000,000 Btu/short ton
Anthracite Coal	25,000,000 Btu/short ton
Residual Fuel Oil #1	135,425 Btu/gal
Residual Fuel Oil #2	138,000 Btu/gal

Source: Army Energy Conservation Investment Program Annual Guidance

Non-Energy Costs and Savings

Non-energy costs and savings include interconnection costs, metering costs, operations and maintenance (O&M) costs and incentives. In the ECIP application, non-energy costs and savings are split into recurring and non-recurring categories. Recurring non-energy costs and savings include costs or savings that occur every year, while non-recurring non-energy costs and savings occur only once.

Interconnection Costs

The local utility may charge a recurring or non-recurring interconnection fee. This should be estimated based on discussion with the utility and included in the ECIP form.

Metering Costs

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the Meter Data Management System (MDMS).[9] This allows the Army to measure and verify renewable energy system performance. Metering costs should be included in the ECIP form.

O&M Costs

Most RE systems require regular maintenance. In the ECIP form, O&M costs are entered as non-energy costs and are split into two categories: recurring and non-recurring. Recurring O&M costs represent annual routine maintenance. Non-recurring O&M costs are one-time costs or savings, such as a PV inverter replacement in year 15.

O&M cost estimates for each technology are provided in the technology-specific sections of this guide. These are based on NREL's Energy Technology Cost and Performance Data for Distributed Generation,[10] which provides estimates of O&M costs based on a compilation of available national-level cost data from a variety of sources. While costs will vary by specific location, this database shows the mean O&M cost as well as one standard deviation from the mean, for PV, wind, biomass, SHW, and GSHPs.

Incentives

The federal government and many states and utilities offer RE incentives to offset the cost of RE projects. RE incentives can be categorized into two primary types:

- **Capital-based incentives** reduce the installed cost of a renewable project. These are often paid upfront as a percent of the installed cost or on a $/kW basis. Capital subsidies include grants, rebates, and tax credits. Grants and rebates may be offered by states, utilities, or private organizations. These should be entered as a utility rebate in the Investment Cost section of the ECIP application. Tax incentives should not be included on the ECIP application. Because ECIP projects are owned by DOD and DOD is not a taxable entity, ECIP projects are not eligible for tax incentives. (RE projects on DOD installations owned by taxable third parties, such as projects implemented through power purchase agreements, are eligible for tax incentives.)

- **Performance-based incentives** are provided as a $/kWh payment for energy generated. These include feed-in tariffs (FITs), renewable energy certificates (RECs), and production tax credits (PTCs). These should be entered as a recurring non-energy savings on the ECIP application.

    - FITs are a state-legislated regulation under which a utility is required to pay for electricity at a fixed rate for the life of the FIT contract (typically 10–20 years). Feed-in tariffs are a newer policy mechanism, and while a number of states are investigating their use, they are only in effect in a few states.

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[9] Army Directive 2014-10 (Advanced Metering of Utilities), dated 4 June 2014, Section 3.b(5).

[10] NREL Energy Technology Cost and Performance Data for Distributed Generation. Accessed March 2015: http://www.nrel.gov/analysis/tech_cost_data.html.

- RECs are tradable commodities that represent proof of electric energy generation from RE resources. REC values vary by technology and state. **ECIP projects are not allowed to sell or swap RECs, so the value of RECs should not be included on ECIP applications.**[11]

- PTCs are tax credits provided by federal and state governments that allow the taxpayer to subtract a portion of taxes owed based on the amount of RE generated. **Because ECIP projects are owned by DOD, and DOD is not a taxable entity, ECIP projects are not eligible for tax incentives.**

At the ECIP application stage, energy managers should research the availability of state and local incentives and identify incentives that may be applied to their projects, as well as the specific limitations and requirements of the incentive. Many incentives have limits around the types and sizes of RE systems that are eligible, as well as the maximum dollar value that will be paid or the number of years the incentive will be paid (in the case of performance-based incentives). Additionally, election of one incentive may preclude another. For example, in California, an installation may choose to apply net metering or a feed-in tariff, but not both. Often, a phone call to the utility can help clarify the availability, value, and limitations of an incentive. Once incentive availability and limitations are understood, incentives should be factored into proposed RE economics. Detailed incentive information is available from the Database of State Incentives for Renewables and Efficiency (DSIRE) website.[12] Estimated prices for RECs are available from broker exchange websites.[13]

Economic Parameters for Estimating Present Value of Future Costs and Savings

Federal energy projects are required to abide by the life-cycle cost methods and criteria described in the Federal Code of Regulations 10 CFR 436, Subpart A, which are detailed in NIST Handbook 135, *Life-Cycle Costing Manual for the Federal Energy Management Program*.[14] The Annual Supplement to Handbook 135 provides tables listing the energy price indices and discount factors that should be used for life-cycle cost analysis. These factors are calculated with the latest discount factors and energy price escalation rates for U.S. Census regions, rate types, and fuel types, and are updated annually. The Building Life Cycle Cost (BLCC) computer program can also be used to calculate these discount factors.

When filling out the ECIP Life Cycle Cost Analysis Summary spreadsheet, discount factors are applied to future year savings and costs. The factor applied depends on several variables:

- Type of project: Projects related to energy conservation, renewable energy resources, and water conservation use the DOE discount rate. Other capital investment projects use the OMB discount rate.

- Type of savings/costs: Different factors are applied for fuel costs and savings vs. non-fuel costs and savings such as repair and replacement.

- Recurrence: Different factors are applied depending on whether the savings/cost occurs once, or recurs every year.

[11] The Memorandum on Department of the Army Policy for Renewable Energy Credits dated May 24, 2012, states that REC swapping is not permitted for RECs owned by the Army. REC swapping by developers (for projects financed by third parties) is allowed.

[12] Database of State Incentives for Renewables and Efficiency (DSIRE). Accessed March 2015: http://www.dsireusa.org/.

[13] SREC Trade. Accessed March 2015: http://srectrade.com/. Flett Exchange. Accessed March 2015: http://flettexchange.com.

[14] NIST Handbook 135 and the Annual Supplement to Handbook 135 are available at: http://energy.gov/eere/femp/building-life-cycle-cost-programs.

The following tables from the Annual Supplement to Handbook 135 should be used to find the appropriate discount rates for future year savings and costs when filling out the ECIP Life Cycle Cost Analysis Summary spreadsheet:

- Table A-1 provides single present value factors for non-fuel, non-annually recurring costs such as repair and replacement costs and salvage value. For example, for a PV system that requires inverter replacement in year 10, use a factor of 0.744 from Table A-1, column 2 ("DOE Discount rate 3.0%"), row 13 (Number of years from base date: 10).[15]

- Table A-2 provides uniform present value factors for non-fuel recurring costs, such as routine maintenance costs. For example, for a PV system that requires the same routine maintenance every year for 25 years, use a factor of 17.41 from Table A-2, column 2 ("DOE Discount rate 3.0%"), row 25 (Number of years from base date: 25).

- Tables Ba-1 through 4 provide modified uniform present value discount factors for energy costs or savings recurring every year over 1 to 30 years, based on the DOE discount rate. They are modified to incorporate energy price escalation rates. Because the energy price escalation rates vary by census region, Tables 1 through 4 each represent a different region. These factors apply only to annual energy usage or energy savings that are assumed to be the same each year over the service period. The BLCC computer program can compute the present value of energy usage and savings that are not the same in each year. For example, for a PV system in California that saves approximately the same amount of energy every year for 25 years, use a factor of 17.57 from Table Ba-4, column 6 ("Commercial electric"), row 25 (number of years from base date: 25). An excerpt from the Annual Supplement to Handbook 135 is shown in Table 3 below.

Table 3. Excerpt from the Annual Supplement to Handbook 135

Table Ba-4. FEMP UPV* Discount Factors adjusted for fuel price escalation, by end-use sector and fuel type.

Discount Rate = 3.0 % (DOE)

Census Region 4 (Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming)

	RESIDENTIAL				COMMERCIAL					INDUSTRIAL					TRANSPORT	
N	Elec	Dist	LPG	NtGas	Elec	Dist	Resid	NtGas	Coal	Elec	Dist	Resid	NtGas	Coal	Gasln	N
1	0.97	0.89	0.94	0.97	0.97	0.85	0.72	0.98	0.98	0.96	0.87	0.75	1.01	0.97	0.94	1
2	1.92	1.73	1.83	1.94	1.92	1.65	1.36	1.93	1.95	1.89	1.70	1.42	2.01	1.93	1.84	2
3	2.84	2.56	2.69	2.92	2.84	2.43	1.98	2.91	2.91	2.80	2.51	2.08	3.04	2.86	2.71	3
4	3.73	3.38	3.55	3.93	3.74	3.21	2.59	3.89	3.84	3.69	3.32	2.72	4.11	3.76	3.56	4
5	4.61	4.19	4.40	4.94	4.62	3.99	3.20	4.90	4.76	4.57	4.13	3.37	5.20	4.63	4.41	5
6	5.44	4.99	5.24	5.96	5.46	4.76	3.81	5.91	5.65	5.41	4.92	4.01	6.31	5.47	5.24	6
7	6.26	5.78	6.07	6.96	6.28	5.51	4.40	6.92	6.53	6.24	5.71	4.65	7.41	6.29	6.07	7
8	7.05	6.56	6.89	7.96	7.09	6.26	5.00	7.91	7.38	7.04	6.49	5.28	8.51	7.10	6.89	8
9	7.81	7.32	7.70	8.95	7.86	7.00	5.58	8.90	8.22	7.81	7.26	5.91	9.60	7.88	7.70	9
10	8.54	8.08	8.48	9.93	8.60	7.73	6.17	9.88	9.05	8.56	8.02	6.54	10.69	8.65	8.49	10
11	9.25	8.83	9.26	10.89	9.32	8.45	6.75	10.85	9.86	9.29	8.77	7.17	11.76	9.41	9.26	11
12	9.95	9.56	10.02	11.83	10.02	9.17	7.33	11.79	10.65	10.01	9.51	7.80	12.79	10.15	10.02	12
13	10.63	10.29	10.76	12.75	10.70	9.87	7.91	12.71	11.43	10.71	10.23	8.43	13.79	10.88	10.76	13
14	11.28	11.01	11.49	13.64	11.36	10.57	8.48	13.61	12.20	11.39	10.95	9.05	14.76	11.60	11.48	14
15	11.92	11.71	12.20	14.52	12.00	11.25	9.04	14.49	12.96	12.05	11.66	9.66	15.70	12.30	12.19	15
16	12.54	12.41	12.89	15.38	12.61	11.92	9.60	15.35	13.71	12.69	12.35	10.27	16.63	12.99	12.88	16
17	13.15	13.10	13.57	16.22	13.21	12.59	10.16	16.19	14.44	13.32	13.04	10.88	17.54	13.67	13.57	17
18	13.74	13.78	14.23	17.05	13.80	13.24	10.71	17.02	15.17	13.94	13.71	11.48	18.44	14.34	14.24	18
19	14.33	14.44	14.88	17.87	14.38	13.89	11.26	17.84	15.89	14.55	14.37	12.08	19.32	15.00	14.90	19
20	14.90	15.10	15.51	18.68	14.93	14.52	11.81	18.64	16.60	15.14	15.02	12.68	20.20	15.65	15.54	20
21	15.45	15.75	16.13	19.47	15.48	15.15	12.35	19.44	17.29	15.72	15.66	13.26	21.08	16.29	16.18	21
22	15.99	16.39	16.74	20.27	16.01	15.77	12.88	20.24	17.98	16.30	16.30	13.85	21.96	16.92	16.81	22
23	16.53	17.02	17.33	21.06	16.54	16.38	13.41	21.04	18.66	16.87	16.93	14.43	22.84	17.54	17.44	23
24	17.06	17.65	17.91	21.85	17.06	16.99	13.94	21.83	19.33	17.43	17.55	15.01	23.74	18.15	18.05	24
25	17.57	18.27	18.48	22.64	17.57	17.59	14.46	22.63	19.99	17.99	18.17	15.59	24.65	18.74	18.66	25
26	18.08	18.88	19.04	23.42	18.08	18.18	14.98	23.43	20.64	18.54	18.77	16.17	25.55	19.33	19.26	26
27	18.58	19.48	19.59	24.20	18.57	18.77	15.50	24.21	21.28	19.09	19.37	16.74	26.45	19.90	19.86	27
28	19.07	20.07	20.12	24.96	19.05	19.34	16.01	24.99	21.91	19.62	19.96	17.30	27.34	20.46	20.45	28
29	19.54	20.65	20.65	25.71	19.53	19.92	16.52	25.75	22.52	20.15	20.55	17.87	28.22	21.01	21.03	29
30	20.01	21.23	21.16	26.45	19.98	20.48	17.03	26.51	23.12	20.67	21.12	18.43	29.10	21.55	21.60	30

[15] This example and following examples are based on the 2013 edition of the Annual Supplement to Handbook 135.

POLICIES AND PERMITS

This section describes some of the policies and permits that impact RE projects.

Net Metering

Net metering programs serve as an important incentive to onsite RE generation that produces energy in excess of the site load. Net metering enables customers to use their own generation from onsite RE systems to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand, enabling customers to receive retail prices for the excess electricity they generate. Without net metering, a second meter is usually installed to measure the electricity that flows back to the provider, with the provider purchasing the power at a rate much lower than the retail rate. Net metering increases the value of the electricity produced by renewable generation and allows customers to "bank" their energy and use it a different time than it is produced, giving customers more flexibility and allowing them to maximize the value of their production. Most states require net metering, but these policies vary widely and do not always apply to all utilities within the state. In addition, many policies place limits on the type and size of systems that qualify. There are often limitations on how much energy can be banked, and in what time period, and this should be considered when sizing systems.

At the ECIP application stage, energy managers should consider whether the proposed RE system may generate energy in excess of site load. If it may, they should look at the provisions of the utility's net metering tariff and determine what types and sizes of RE systems are allowed and economic. These limits should be factored into proposed RE types, sizes, and economics. Especially because renewable resources vary, the actual RE production versus load of the facility need to be analyzed on an hourly basis to determine the hourly output from the RE system and site electrical load. In addition, larger facilities typically have two separate components to the utility bill—an electricity consumption charge per kilowatt-hour and a demand charge per kilowatt of peak load. Many RE systems will only offset a portion of the demand charges. The details can be extremely important to the economics of these systems. In some cases, using net metering can preclude the use of other favorable tariffs. If a RE project will never generate enough energy to export power to the grid, or is not connected to the utility grid, then net metering does not apply.

Detailed net metering information is available from the Database of State Incentives for Renewables and Efficiency (DSIRE) website.[16]

Interconnection Limits

Interconnection standards govern how a renewable electricity technology, such as photovoltaics (PV) or wind, will connect to the power grid. Many states have adopted streamlined interconnection standards that require utilities to allow customers to connect onsite power systems of a certain type or size. Some state policies are only guidelines, and some apply only to investor-owned utilities and not to municipal utilities or rural electric cooperatives. Without these standards, the local utility determines the requirements and limitations for connecting a system to the grid.

Interconnection issues can make or break a project. In states without comprehensive interconnection standards in place, it can be more difficult, burdensome, and expensive to connect a system to the grid. Additional requirements such as

[16] Database of State Incentives for Renewables and Efficiency (DSIRE). Accessed March 2015: http://www.dsireusa.org/.

engineering studies, insurance provisions, or non-standard fees can significantly increase project cost. On the other hand, utilities may view Army RE projects favorably for their ability to help the utility meet RE generation requirements and enhance the utility's profile with its customers. Projects that benefit both the utility and the Army will likely experience a smoother interconnection process.

In general, systems that are sized such that they do not export energy may have fewer interconnection issues. Many ECIP projects will fall in this size range. At the ECIP application stage, energy managers should identify the availability of standardized interconnection with the local utility and understand the specific limitations and requirements. These limits should be factored into proposed RE types, sizes, and economics. If interconnection is identified as a concern at this stage, the installation energy manager can begin working with the utility early to resolve issues and move forward.

Detailed interconnection information is available from the DSIRE website.[17] The website also provides state-by-state details on interconnection standards and guidelines. Another relevant and useful resource is the Freeing the Grid (FTG) website.[18] It provides information on a state-by-state basis about the quality of net metering rules and interconnection policies within those states and assigns a letter score (A, B, C, D, F, or N/A) to each state. It provides detailed information on related policies for each state. Finally, utility websites or utility customer service representatives can provide interconnection requirements specific to the particular utility, technology, and project size being considered.

National Environmental Policy Act

The National Environmental Policy Act (NEPA) requires federal agencies to integrate environmental values into their decision making processes by considering the environmental impacts of their proposed actions and reasonable alternatives to those actions. To meet NEPA requirements, federal agencies prepare a detailed statement known as an Environmental Impact Statement (EIS). The EIS includes an environmental assessment (EA). **The EA is one of the first steps in scoping out a potential RE system at a DOD installation, as the EA can take anywhere from 6 months to 2 years and needs to be completed before an RFP is issued to ensure that the project is allowable.** In order to determine what specifically is required for the NEPA at each site, environmental experts within the organization should be consulted early on in the process. Depending upon site location and Native American and/or other cultural artifacts, the National Historic Preservation Act and Endangered Species Act (ESA) might need to be evaluated by the environmental experts. In some cases a categorical exclusion applies to certain building-integrated RE technologies, but this needs to be determined on a case-by-case basis.

Army Metering Policy

Per Army policy, advanced meters must be installed and connected to MDMS on all ECIP projects.[19] Installed meters must comply with the Army's Central Metering Program, which includes connecting to a secure network. This allows the Army to effectively measure and verify renewable energy system performance. All RE projects will need to have some type of measurement and verification, metering being the most common method. However, some RE technologies do not easily lend themselves to meter performance. Specific metering guidance for each RE technology is provided in the technology specific guidance sections below. Budget for advanced meters should be included in the ECIP application.

[17] Database of State Incentives for Renewables and Efficiency (DSIRE). Accessed March 2015: http://www.dsireusa.org/.

[18] Freeing the Grid 2015. Accessed March 2015: http://freeingthegrid.org/.

[19] Army Directive 2014-10 (Advanced Metering of Utilities), dated 4 June 2014, Section 3.b(5).

Army Sustainable Design and Development Policy

The Army Sustainable Design and Development Policy[20] states that renewable energy systems shall be designed to function absent of normal utility power and have the ability to divert power to mission critical assets as appropriate. The ability to island adds design complexity and cost to the system, and should be taken into account when designing and budgeting for ECIP projects.

[20] Sustainable Design and Development Policy Update, dated 16 Dec 2013, Section 5.a.ii.b. http://www.usace.army.mil/Portals/2/docs/Sustainability/Hydrology_LID/ASAIEE_SDD_Policy_Update_2013-12-16.pdf.

TECHNOLOGY-SPECIFIC GUIDANCE

This section provides information on six RE technologies: PV, SHW, SVP, GSHP, biomass, and wind. Each technology section includes a description of the technology, project development considerations, guidance on estimating costs and energy production, suggested trainings, and examples of DOD installations that have successfully installed this technology.

PHOTOVOLTAICS

Photovoltaics (PV) are semiconductor devices that convert sunlight directly into electricity. They do so without any moving parts and without generating any noise or pollution. Rooftops, carports, and ground-mounted arrays are common mounting locations.

Technology Description

PV cells are made of semiconductor materials, with the most common being crystalline silicon. The amount of electricity a PV cell produces depends on its size, its conversion efficiency, the tilt and azimuth of the collector, and temperature and weather conditions. An inverter is required to convert the direct current (DC) to alternating current (AC) of the desired voltage compatible with building and utility power systems. The remaining system components include mounting systems and electrical connections (conductors/conduit, switches, disconnects, and fuses). Grid-connected PV systems feed power into the facility's electrical system and do not include batteries. Figure 2 shows the major components of a grid-connected PV system and illustrates how these components are interconnected.

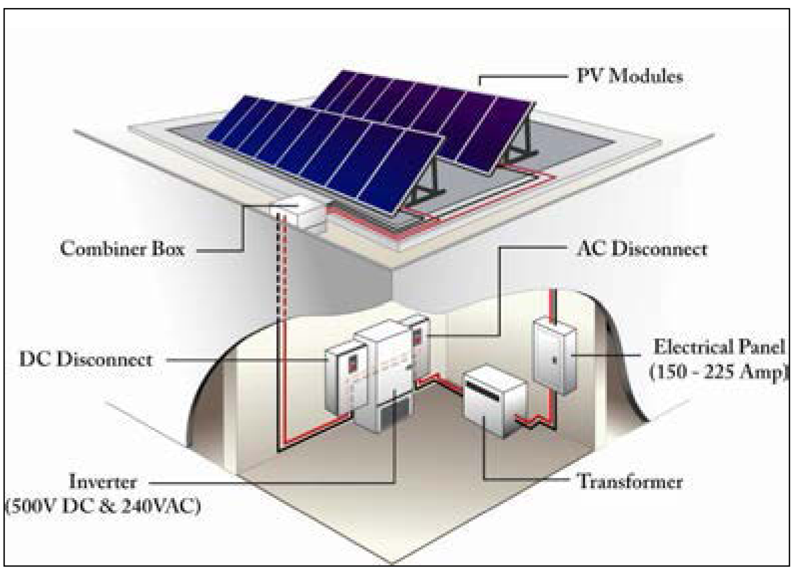

Figure 2. Depiction of major components of grid-connected PV systems

Illustration by Jim Leyshon, NREL

PV Array: The primary component of a PV system, the PV array, converts sunlight to electrical energy. All other components simply condition or control energy use. Most PV arrays consist of interconnected PV modules that range in size from 50 W to 300 W [peak DC-Watt (DC-W)]. Peak watts are the rated output of PV modules at standard operating conditions of 77°F and insolation of 1,000 W per square meter. Because these standard operating conditions are nearly ideal, the actual output will be less under typical environmental conditions. PV modules are the most reliable components in any PV system. They are engineered to withstand extreme temperatures, severe winds, and impacts. *ASTM E 1038-93* subjects modules to impacts from one-inch hail at terminal velocity (55 mph) at various parts of the module. PV modules have a life expectancy of 25–30 years, and manufacturers typically guarantee them to produce at least 80% power after 25 years of use. Several manufacturer choices exist, but it is recommended that the PV be approved by Go Solar California[21] and that the system undergo a competitive bid process.

Inverters: PV arrays provide DC power at a voltage that depends on the configuration of the array. This power is converted to AC power at the required voltage and number of phases by the inverter. Inverters enable the operation of commonly used equipment, such as appliances, computers, office equipment, and motors. Current inverter technology provides true sine wave power at a quality often better than that of the serving utility. A location for the inverter along with the balance-of-system equipment should be considered.

Inverters are available that include most or all of the control systems required for operation, including some metering and data-logging capability. Inverters must provide several operational and safety functions for interconnection with the utility system. The Institute of Electrical and Electronic Engineers (IEEE) maintains the standard *P929 Recommended Practice for Utility Interface of Photovoltaic Systems*, which allows manufacturers to write "Utility-Interactive" on the listing label if an inverter meets the requirements of frequency and voltage limits, power quality, and non-islanding inverter testing. Underwriters Laboratory (UL) maintains *UL Standard 1741, Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*, which incorporates the testing required by *IEEE 929* and includes design (type) testing and production testing.

Balance-of-System Components: Balance-of-system components include mounting racks and hardware for the panels, and wiring for electrical connections.

Mounting systems are the structures that hold the module to the ground, roof, or carport. There are typically options for directly anchoring systems to the ground or roof, or ballasting them without penetration. The selection of mounting type is dependent on many factors including installation size, economics, land constraints, latitude, and local weather. The mounting system design will need to meet applicable local building code requirements with respect to snow, wind, and seismic zones. Mounting systems must withstand local wind loads, which range from 90–120 mph for most areas or 130 mph or more for areas with hurricane potential. Depending on the region, snow and ice loads must also be a design consideration for the mounting system.

Electrical connections, including wiring, disconnect switches, fuses, and breakers, are required to meet electrical code for both safety and equipment protection. Typically wiring from the arrays to the inverters and from the inverters to the point of interconnection is run as direct burial through trenches for ground-mount applications, or in above-ground for rooftop or carport applications.

Types of Photovoltaic Systems

When developing an ECIP PV project, where the project will be located on the installation and what kind of system will need to be decided first. Typical system types are discussed below.

Ground-mounted PV systems are usually the lowest-cost option to install on a dollar per DC-W basis. There are several mounting options available, each having different benefits for different ground conditions. Table 4 outlines energy density values that can be expected from each of the different system types.

[21] Go Solar California. Accessed March 2015: http://www.gosolarcalifornia.org/equipment/pv_modules.php.

Table 4. Energy Density by Panel and System for Ground-Mounted PV

System Type	Fixed-Tilt Energy Density (DC-W/ft²)	Single-Axis Tracking Energy Density (DC-W/ft²)
Crystalline Silicon	4	3.3
Thin Film	3.3	2.7
Hybrid High Efficiency	4.8	3.9

When considering a ground-mounted system, an electrical tie-in location should be identified to determine how the energy would be fed back into the grid. Fixed-tilt systems are installed at a specified tilt, and are fixed at that tilt for the life of the system. Single-axis tracking systems have a fixed tilt on one axis, and a variable tilt on the other axis. The system is designed to follow the sun in its path through the sky. This allows the solar radiation to strike the panel at an optimum angle for a larger part of the day than can be achieved with a fixed-axis system. A single axis tracking system can collect up to 30% more electricity per capacity than a fixed-tilt system. The drawbacks include increased O&M costs, less capacity per unit area (DC-W/ft^2), and greater installed cost (dollar per DC-W). Single-axis tracking systems are typically installed for larger ground-mount arrays in the southwest regions of the United States with better direct normal radiation.

Roof-mounted PV systems are usually more expensive than ground-mounted systems, but roofs are a convenient location because they do not require ground area and are usually unshaded. Large areas with minimal rooftop equipment are preferred, but equipment can sometimes be worked around if necessary. If a building has a sloped roof, flush-mounted installations can achieve power densities of 11 DC-W/ft^2 when installing a typical crystalline silicon panel. If the roof of the building is flat, rack-mounted systems can achieve power densities of 8 DC-W/ft^2 for a crystalline silicon panel. Typically, PV systems are installed on roofs that are less than 5 years old or on roofs with more than 20–30 years left before replacement.

Carport PV systems are usually the most expensive of the three location options, due to the extra cost of constructing the carport, but may be a good option for space-constrained installations. Additionally, PV carports serve a dual purpose by providing shelter for vehicles while also generating RE. Carport PV systems are typically tilted at 5° and flush-mounted with power densities of 11 DC-W/ft^2. An electrical tie-in location should be identified to determine how the energy generated by the PV system will be fed back into the grid.

Project Development Considerations

Key project development considerations for siting, system design, estimating savings, and policies and permits are presented in this section.

Siting

Mission Impact

DOD mission impact is the most important consideration for siting a PV system, and any potential mission impacts should be taken into account at this stage. The most common mission impact concern associated with PV systems is potential glare around airports and helicopter landing strips. There are numerous resources available to assist in properly siting PV systems next to airports, and a list of some of the foundational resources is provided below:

1. Technical Guidance for Evaluating Selected Solar Technologies on Airports: http://www.faa.gov/airports/environmental/policy_guidance/media/airport_solar_guide_print.pdf

2. Interim Policy, Federal Aviation Administration Review of Solar Energy System Projects on Federally Obligated Airports: https://www.federalregister.gov/articles/2013/10/23/2013-24729/interim-policy-faa-review-of-solar-energy-system-projects-on-federally-obligated-airports

3. Solar Glare Hazard Analysis Tool (SGHAT). The SGHAT was designed to determine whether a proposed solar energy project would result in the potential for ocular impact: https://ip.sandia.gov/technology.do/techID=120

4. Airports Offer Unrealized Potential for Alternative Energy Production - 14 January 2012: http://www.aphis.usda.gov/wildlife_damage/nwrc/publications/12pubs/devault123.pdf

5. Siting Solar Photovoltaics at Airports: http://www.nrel.gov/docs/fy14osti/62304.pdf

In addition to addressing potential glare issues, the master planning department should be consulted to ensure that any available ground area is not obligated for future construction (for ground-mount systems), to ensure that the target buildings are planned to exist for at least 25 years (for rooftop systems), and to ensure that any potential parking lot space is not going to be repurposed over the next 25 years (for carport systems).

Orientation and Tilt

PV panels should be oriented facing south (in the northern hemisphere) and mounted with a tilt angle that ranges from 0° to an angle equal to latitude. Flat roof installations on commercial buildings are typically installed with tilt angles that range from 0° to 20°, and sloped roof installations are typically mounted flush to the roof. Orientation and tilt has a lesser effect on production at lower latitudes, and as Figure 3 and Figure 4 show, the system can be installed ± 30° off of due south and with a tilt angle that ranges from 5° to 45° and still produce 95% to 100% of the peak output of an array that faces due south at a tilt angle equal to latitude. This clearly illustrates that the designer has flexibility in his design around both tilt and orientation as long as the system generally faces south and has a tilt angle that ranges from 0° to latitude.

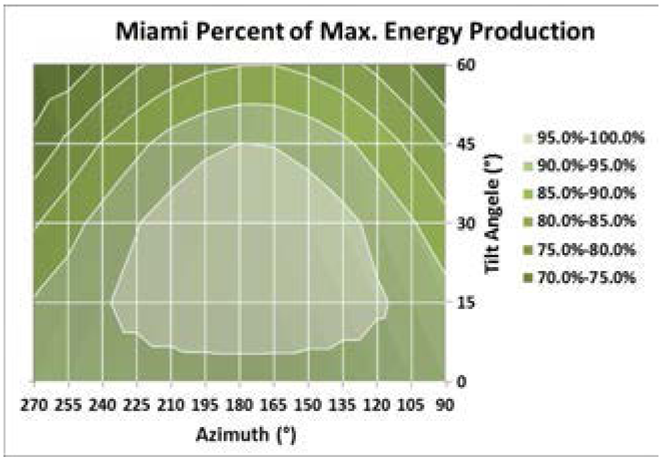

Figure 3. Percent of maximum energy production from PV system in Miami, Florida

Illustration by Jesse Dean, NREL

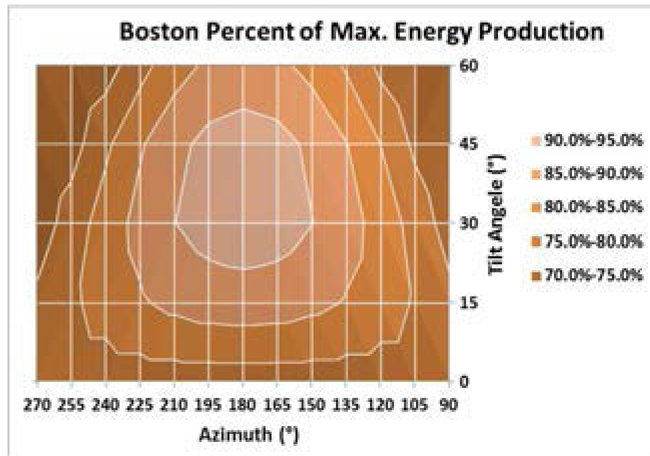

Figure 4. Percent of maximum energy production from PV system in Boston, Massachusetts

Illustration by Jesse Dean, NREL

As a general rule of thumb, flat roof installations should be mounted at 10° to 20°, sloped roof installations should be mounted flush to the roof, and fixed-tilt ground-mount installations should be mounted at 15° to 30°.

Shading

PV panels are very sensitive to shading. When shade falls on a panel, that portion of the panel is no longer able to collect the high-energy beam radiation from the sun. PV panels are made up of many individual cells that all produce a small amount of current and voltage. These individual cells are connected in series to produce a larger current. If an individual cell is shaded, it will act as resistance to the whole series circuit, impeding current flow and dissipating power rather than producing it. An onsite shading assessment should be conducted with a solar pathfinder, and PV arrays should not be located in locations with annual solar access values fewer than 90%. If a shading assessment is not available, then as a general rule of thumb, installations should avoid locations that are shaded between 9 a.m. and 3 p.m.

Setbacks

Most local fire codes have developed standards for setback distances from roof edges. For large commercial buildings, the standard setback requirement is 6 ft, and for smaller residential systems, the standard setback requirement is 2 ft. These setbacks should be taken into account when determining where a PV system should be placed.

Historical Considerations

A fairly large percentage of DOD buildings are considered historic structures, and the historic preservation office should be consulted to discuss any potential historic preservation issues. For typical flat roof, multi-story commercial buildings, the historic preservation office may ask for documentation that shows that the array is not visible from the street. Energy managers are encouraged to reference the publication "Implementing Solar PV Projects on Historic Buildings and in Historic Districts"[22] for more information on historic building considerations.

Security

The Army is committed to reducing physical security risks and protecting national security at its installations. Accordingly, the selected developer of the PV Project will be required to comply with, and incorporate into all project-related contracts and subcontracts, certain Federal Acquisition Regulations and Defense Federal Acquisition Regulations Supplement solicitation provisions and contractual clauses. These provisions and clauses impose Buy American Act restrictions on contracts for PV devices, prohibit the award of contracts to terrorist countries, restrict contracts to companies controlled by a foreign government in certain circumstances, and require foreign representatives providing contractual services on Army installations to be screened.

Building Structural Integrity

PV systems typically add a dead load of 3–6 lb/ft^2 to the roof, and the engineering department should be contacted to flag any facilities with known structural integrity issues prior to moving forward with siting a PV system. Although the detailed structural analysis of the building should fall within the scope of the installer and is outside of the scope of the energy manager, the engineering department will typically have a list of facilities that they know cannot support a PV system and should be ruled out. Many World War I era warehouse facilities would fall into this category, for example. Additionally, systems should be designed to withstand wind loads.

Roof Age and Condition

PV systems will last for a minimum of 25 years, so PV systems should be installed on roofs that have a useful life of at least 25 years. The impact on warranties of existing roofs should be considered. The engineering department should be consulted to determine the age and condition of each roof, and any roof that needs to be replaced or re-roofed should do so prior to the installation of a PV system. If this is the case, then PV system installations can be staged to occur after the re-roofing schedule for selected facilities.

System Design

Equipment Selection

In general, the site does not need to go through the process of specifying certain panels or inverters prior to submitting an ECIP application. The primary exception to this would be instances in which the DOD is using panels made by organizations such as the Department of Corrections (DOC) that provide a partnership opportunity.

Electrical Interconnection and Power Factor Correction

Detailed electrical interconnection studies are typically beyond the scope of what is required for an ECIP application. For larger ground-mount and carport PV systems, the local engineering department should be consulted to determine where the system will tie into the local electrical grid and to determine if any step-up transformers will be required. If this is the case, the costs of the additional transformers should be included in the ECIP application.

[22] Kandt, A.; Hotchkiss, E.; Walker, A.; Buddenborg, J; Lindberg, J. (2011). *Implementing Solar PV Projects on Historic Buildings and in Historic Districts*. TP-7A40-51297. Golden, CO: National Renewable Energy Laboratory. Accessed March 2015: http://www.nrel.gov/docs/fy11osti/51297.pdf.

Newer inverters for PV systems can come with built-in power factor correction. If a site is installing an onsite PV system that offsets the majority of the electrical load and does not specify an inverter with power factor correction, the post-installation power factor can be very low, which can result in very expensive power factor charges. On the other hand, if an inverter with power factor correction was installed, it could improve the power factor of the entire site and help to save the site money rather than add cost. Inverters with power factor correction capabilities should be evaluated for PV projects that offset more than 15% of the overall site electricity usage.

Safety

Unless the system is designed to island as part of a microgrid, PV inverters are required to automatically shut down during a grid outage to prevent feeding electricity back onto utility lines and potentially harming line crews. The fire department should be aware of the location of the PV system and know how to disconnect the PV system from the grid in case of fire.

Metering

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the MDMS.[23] PV monitoring systems come standard with most installations and should be specified in the contract to ensure proper operation and energy production in out-years. String-level sub-metering can be provided with advanced combiner boxes and should be considered as a part of the installation.

Estimating Savings

Demand Savings

A PV system's impact on peak demand is a function of both the hourly load profile of the site and the type and size of the PV system installed on the site. Single-axis tracking PV systems have a flatter production profile than fixed-tilt systems and can provide better peak demand savings by offering higher late afternoon production, when peak demand is often set. It is generally very difficult to estimate peak demand savings without a detailed hourly load study. The site is encouraged to calculate the estimated peak demand savings based on the hourly energy production from the solar system and the hourly load profile of the base.

Equipment Lifetime

PV panels are warrantied for 20–25 years, and their lifetime should be assumed to be 25 years. Inverters are typically warrantied for 10–20 years, and energy managers have the choice of purchasing an optional 20-year warranty for inverters. This additional warranty will slightly increase the installed cost of the system. Energy managers should plan for a one-time inverter replacement and include this as a non-recurring cost in the ECIP application or adjust the installed cost of the system to account for the 20-year inverter warranty cost premium.

Policies and Permits

The site should contact the local utility to get a listing of standard interconnection procedures, net metering regulations, and local incentives. One or two meetings with the local utility are typically required to ensure that the proposed system complies with local interconnection standards and utility regulations.

[23] Army Directive 2014-10 (Advanced Metering of Utilities), dated 4 June 2014, Section 3.b(5).

Estimating PV Capital Costs and O&M Costs

Capital Costs

PV costs have come down significantly in recent years, and are expected to continue to drop.[24] Therefore, it is important to look at recent cost data when estimating PV capital costs. NREL's Energy Technology Cost and Performance Data for Distributed Generation website,[25] which was updated in August 2013, shows a 200 kW PV system averages approximately \$3.35/W, with a range of approximately \$2.70–\$4.00/W. SEIA's U.S. Solar Market Insight Report, Q1 2014, estimates a 300 kW system averages approximately \$2.53/W (using a bottom-up cost model) or \$3.72/W (based on data reported by state and utility incentive programs, which may be out of date as these represent systems quoted well prior to the installation and connection date).[26] DOE's Photovoltaic System Pricing Trends, 2014 Edition, estimates 200 kW systems installed in 2014 average \$2.54/W.[27] Based on market research reports from sources such as SEIA, Bloomberg New Energy Finance, and PV News, as well as NREL PV cost models, an estimate of PV costs for various system types and sizes is provided in Table 5. These costs are meant to be a starting place for energy managers estimating PV system costs. Actual costs could vary substantially based on local conditions, system design, and other factors. These costs are for fixed systems. Tracking systems typically cost an additional \$0.10-\$0.15/W.

Table 5. Approximate 2013 PV System Costs for Preliminary Analysis

System Size (kW)	Ground Mount (\$/W)	Roof Mount (\$/W)	Carport (\$/W)
25 kW	X	\$3.00	\$4.00
100 kW	X	\$2.70	\$3.70
250 kW	X	\$2.60	\$3.60
500 kW	\$2.50-\$3.00	\$2.55	\$3.55
1000 kW	\$2.25	\$2.50	\$3.50
5,000 kW and up	\$1.75	X	X

Note: "X" indicates this is not likely a practical size for this type of system.

O&M Costs

PV panels will come with a 25-year performance warranty. Inverters come standard with a five- or 10-year warranty, with extended warranties available, and should be expected to last 10–15 years. System performance should be verified on a

[24] Feldman, D.; Margolis, R.; James, T.; Goodrich, A.; Barbose, G.; Darghouth, N.; Weaver, S.; Wiser, R. (2013). *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. 2013 Edition (Presentation)*. SunShot, U.S. Department of Energy (DOE). 29 pp.; PR-6A20-60207. Accessed March 2015: http://www.nrel.gov/docs/fy13osti/60207.pdf.

[25] NREL Energy Technology Cost and Performance Data for Distributed Generation. Accessed March 2015: http://www.nrel.gov/analysis/tech_cost_data.html.

[26] *SEIA Solar Market Insight Report Q1 2014*. Solar Energy Industries Association. Accessed March 2015: http://www.seia.org/research-resources/solar-market-insight-report-2014-q1.

[27] Feldman, D.; Barbose, G.; Margolis, R.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. (2014). *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. 2014 Edition (Presentation)*. SunShot, U.S. Department of Energy (DOE). 32 pp.; PR-6A20-62558. Accessed March 2015: http://www.nrel.gov/docs/fy14osti/62558.pdf.

vendor provided website. Wire and rack connections should be checked. For economic analysis, an annual O&M cost of $12.50/DC-kW is typically used for fixed-axis grid-tied PV systems. An annual O&M cost of $20/DC-kW is typically used for single-axis tracking systems. A one-time inverter replacement cost is typically assumed in year 15 at a cost of approximately $0.10/W.

Estimating Energy Production

Energy production can be estimated with one of the following free software tools:

- PVWatts: http://pvwatts.nrel.gov
- RETScreen: http://www.retscreen.net
- Solar Advisor Model: https://sam.nrel.gov.

PVWatts is the simplest of the three software tools and is the focus of this guide. In order to estimate energy production via PVWatts, the energy manager will need to know the following:

- *DC System Size (kW)* — Nameplate size of the system.
- *Array Type* — Fixed tilt, single-axis tracking, or dual-axis tracking.
- *DC to AC Derate Factor* — Accounts for inverter and wiring losses, mismatch, shading, and soiling.

  The default is 0.77. For systems that have no shading, 0.81 is recommended since modern inverters have higher efficiencies than the default in PVWatts.
- *Tilt (deg)* — Tilt angle of the array.
- *Azimuth (deg)* — The azimuth angle is 180° for systems that face due south and can be adjusted based on the orientation of the array.

The monthly energy production in units of kWh/month can then be used to determine cost savings and economics.

Example Calculation

Example 1: Flat Roof Commercial Building

A small complex of four facilities on a DOD installation is being considered for a PV system. The facility passed the project development considerations listed on pages 4-5.The total rooftop area available for solar was calculated based on an onsite walkthrough and using Google Earth's ruler function to measure linear distances. In addition to Google Earth, the latest version of PVWatts also has a drawing tool that can be used to calculate roof area. The main drawbacks of the PVWatts drawing tool are that you can only identify one array location and that you cannot differentiate between flush roof-mount and tilted flat-roof installations. Each red block in Figure 5 represents a potential location for a PV array. The arrays were located in areas with no southern obstructions, at least 6 feet from a roof edge and far enough away from each rooftop object to avoid shading. A typical rule of thumb is to set PV arrays back from rooftop shading objects a distance equal to the height of the object.

Figure 5. Facility complex with potential rooftop PV locations indicated in red

Image credit: © 2014 Google Earth, alterations by Jesse Dean

Figure 5 illustrates that due to the large number of rooftop obstructions, the usable area for a PV system is only a fraction of the total rooftop area. The length and width of each array was input into a worksheet, and a utilization factor was assigned to each roof area (see Table 6).

Table 6. Potential Rooftop PV Locations

Building	Length (ft)	Width (ft)	Total Area (ft^2)	Utilization (%)	Usable Area (ft^2)	Annual Solar Access	Total Size (kW)
	45	20	900	100%	900	100%	7
	45	20	900	100%	900	100%	7
73	20	15	300	100%	300	100%	2
	62	117	7,254	80%	5,803	100%	46
	60	30	1,800	80%	1,440	100%	12
72	30	100	3,000	80%	2,400	100%	19
71	20	370	7,400	100%	7,400	100%	59
	290	15	4,350	100%	4,350	100%	35
70	180	15	2,700	100%	2,700	100%	22
Total			***28,604***		***26,193***		***210***

The percent utilization factor can be used to further reduce the estimated system size if there are small roof vents or other obstructions. Percent utilization factor is simply an estimate of the percent of the allocated roof area that can be used for PV panels. The solar access value is also noted for each location, and if the solar access value is fewer than 100% due to shading, then this derate needs to be updated in PVWatts (further information regarding derate is provided in PVWatts). The system size was calculated using the power density assumption provided above for flat roof PV systems (8 W/ft^2) to estimate the total system size: (26,193 ft^2 x 8 W/ft^2)/1,000 W/kW = 209.5 kW.

Once the system size is determined, the following information can be input into PVWatts to estimate energy production:

- Location: Denver, CO
- DC System Size: 210 kW
- Array Type: Fixed (roof mount)
- Azimuth: 165° (slightly east of south per Google Earth image)
- Tilt Angle: 10° (standard for flat roof installations)
- DC to AC Derate: 81% (as there is no shading).

The annual energy production estimate from PVWatts is 274,531 kWh/yr. The next step in the process is to input the local utility rate, local incentives, and economic parameters into the ECIP form. The parameters outlined in Table 7 below must be collected.

Table 7. PV Example, Economic Parameters

Parameter	Value	Notes
Installed Cost	$3.35/DC-W	From: http://www.nrel.gov/analysis/tech_cost_dg.html
O&M Cost	$12.5/DC-kW/yr	
Analysis Period	25 years	
Energy Savings	936.69 MMBtu	[(274,531 kWh/yr x 3,412 Btu/kWh) / (1,000,000 MMBtu/Btu)] = 936.69 MMBtu
Electric Rate	$0.095/kWh	Blended rate includes both electric rate and demand rate
Federal Tax Incentive	$0.00	Because this will be purchased by the agency
Capacity-Based Incentive	$0.00	Via Xcel Solar Rewards program there is no capacity-based incentive
Production-Based Incentive	$0.11/kWh	Via Xcel Solar Rewards program

The installed cost should be adjusted upward by 10% to account for the government cost premium. The investment costs as outlined in the ECIP form are shown in Table 8 below.

Table 8. PV Example, Investment Costs

Parameter	Value	Notes
Construction Cost	$773,850	210,000 W x $3.35/DC-W x 1.1 (10% adder) = $773,850
SIOH (5.7%)	$44,109	Calculated automatically in ECIP worksheet
Design Cost (4%)	$30,954	Calculated automatically in ECIP worksheet. However, most of the quoted prices for RE already include design costs, so energy managers should consider removing the additional 4% design cost for their project or reducing the construction cost estimate by 4% so that design costs are not double counted.
Salvage Value of Existing Equipment	$0	
Public Utility Company Rebate	$0	
Total Investment	$848,913	Calculated automatically in ECIP worksheet

The energy savings are input into the ECIP form as shown in Table 9 below.

Table 9. PV Example, Energy Savings in ECIP Form

Parameter	Value	Notes
Electric Cost	$27.84/MMBtu	$0.095/kWh / 3,412 Btu/kWh x 1,000,000 MMBtu/Btu = $27.84/MMBtu
Energy Savings	937 MMBtu/yr	
Annual Savings	$26,077	Calculated automatically in ECIP worksheet
Discount Factor	17.57	Based on 25-year discount factor for electricity for Colorado
Discounted Savings	$458,181	Calculated automatically in ECIP worksheet
Total Savings	$458,181	Calculated automatically in ECIP worksheet

The non-energy costs and savings are input into the ECIP form as shown in Table 10 below.

Table 10. PV Example, Non-Energy Costs and Savings in ECIP Form

Parameter	Value	Notes
Annual Recurring	$27,573	210 kW x $12.5/kW = -$2,625 to account for O&M plus ($0.11/kWh x 274,531 kWh/yr) to account for production incentive
Discount Factor	17.41	Based on discount factor for finding the present value of annually recurring uniform costs (non-fuel)
Discounted Cost	$480,053	Calculated automatically in ECIP worksheet

The non-recurring costs and savings are input into the ECIP form as shown in Table 11 below.

Table 11. PV Example, Non-Recurring Costs and Savings in ECIP Form

Parameter	Value	Notes
Non-Recurring	($21,000)	210,000 W x $0.1/W = $21,000 for inverter replacement in year 10
Discount Factor	0.741	Single present value factor for finding the present value of future single costs (non-fuel) at year 10
Discounted Cost	($15,540)	Calculated automatically in ECIP worksheet

The system economics are summarized in the ECIP form as shown in Table 12 below.

Table 12. PV Example, Summary in ECIP Form

Parameter	Value	Notes
First-Year Dollar Savings	$52,811	Calculated automatically in ECIP worksheet
Simple Payback	16.1	Calculated automatically in ECIP worksheet
Total Net Disc. Savings	$922,694	Calculated automatically in ECIP worksheet
SIR	1.09	Calculated automatically in ECIP worksheet

For this example, the SIR is barely above 1, so the project would need to score well in all the non-energy savings/economics categories to be approved.

Example 2: Carport PV System

A carport PV system was investigated for the same location, and the potential carport PV system locations were calculated in a similar fashion. It should be noted that just the parking spaces should be included in the area calculations for carports, and as there is no row-to-row spacing for a carport, the power density assumption increases from 8 W/ft^2 to 11 W/ft^2. The array locations are provided in blue in Figure 6.

Figure 6. Example parking lot

Image credit: © Google Earth, alterations by Jesse Dean

The total array length and utilization are provided in Table 13. The utilization for a carport is typically 100% as there are no obstructions, and the typical tilt angle for a carport is 5°. The annual solar access value for each array was assumed to be 95% for this location due to shading from surrounding trees, and the AC to DC derate was updated accordingly.

Table 13. Potential Carport PV Location Information

Parking Lot	Length (ft)	Width (ft)	Total Area (ft^2)	Utilization (%)	Usable Area (ft^2)	Solar Access Value	Total System Size (kW)
	160	16	2,560	100%	2,560	95%	28
	150	32	4,800	100%	4,800	95%	53
	165	32	5,280	100%	5,280	95%	58
	170	32	5,440	100%	5,440	95%	60
Z Lot	125	32	4,000	100%	4,000	95%	44
Total			***22,080***		***22,080***		***243***

The total system size was calculated assuming a power density of 11 W/ft^2 as system size = 11 W/ft^2 x 22,080 ft^2 x (1 kW/1,000 W) = 243 kW. The site would need to find a place to tie the system into the local utility grid. At this point, a similar process would be followed as provided in Example 1 to calculate energy production and economics.

Training

A comprehensive FEMP training walks through all the steps provided in this guide in more detail. Energy managers who are interested in pursuing an onsite PV system are encouraged to take this online training:

> Selecting, Implementing, and Funding Photovoltaic Systems in Federal Facilities:
> http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=140

Army Bases That Have Successfully Installed PV Funded by ECIP

USAG Presidio of Monterey and Fort Hunter Liggett are two Army bases that have successfully installed onsite PV systems with ECIP program funding. The Fort Hunter Liggett system included a battery as well (Table 14).

Table 14. PV System Base Contacts

Name	Base	Title	Phone	Email
Todd Dirmeyer	US Army Garrison Fort Hunter Liggett	Energy Manager	(831) 386-2429	todd.a.dirmeyer.civ@mail.mil
Jay Tulley	USAG Presidio of Monterey, California	Energy Manager	(831) 242-7508	jay.h.tulley.civ@mail.mil

SOLAR HOT WATER

Solar hot water (SHW) is a proven and readily available technology that directly substitutes RE for conventional water heating fuel sources such as electricity, propane, or natural gas.

Technology Description

SHW systems use solar collectors to capture sunlight to heat water (or an antifreeze liquid) that is then moved from the collector to a storage tank Figure 7. There are two types of systems: *active* and *passive*. Active systems use electricity to pump the fluid and have a reservoir or tank for heat storage and subsequent use. Passive systems rely on natural convection and water pressure during draw to move fluids and require no circulation hardware. The systems may be used to heat water in homes, businesses, or for industrial uses. In many climates, a SHW system can provide up to 80% or more of the energy needed to heat water. SHW systems almost always require a backup system for cloudy days and times of increased demand. Conventional natural gas or electric water heaters typically provide backup, so hot water is always available regardless of the weather or demand.

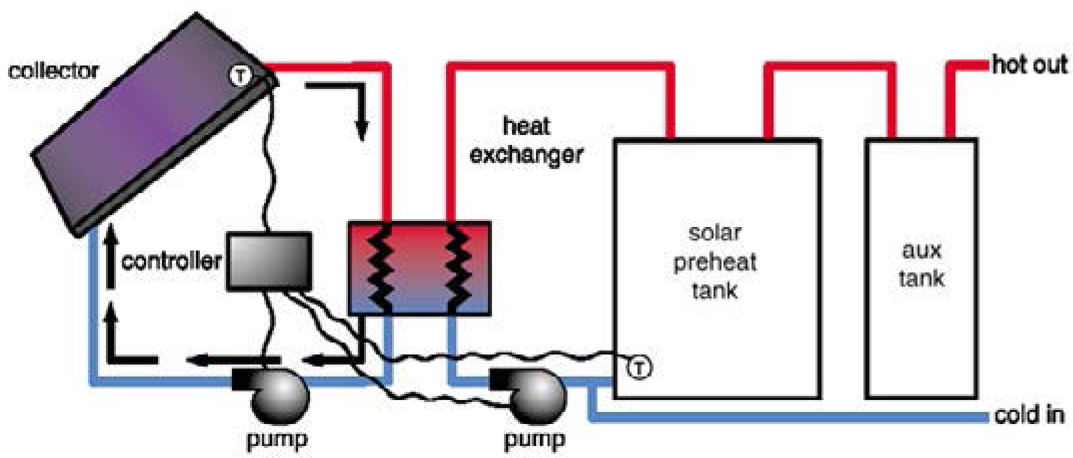

Figure 7. Schematic of an active SHW system with freeze protection

Illustration by Jim Leyshon, NREL

Collectors: There are three, primary types of solar collectors used for common SHW systems: unglazed, glazed flat plate, and evacuated tube. A fourth type of collector, parabolic trough, is only used to heat water for very large facilities or for high-temperature applications including electric generation. Typically, unglazed collectors are used for heating pools and utilize a dark absorber plate (metal or plastic) without a cover. Conventional flat-plate collectors are insulated boxes with glass covers that contain a dark thin copper plate used to absorb the sun's heat underneath. The terms *single*- and *double-glazed collector* come from the number of glass plates on the flat-plate collector. The collector housing is typically steel or aluminum. Evacuated-tube solar collectors use transparent glass tubes that contain a metal absorber tube attached to a fin. Most collectors sold in the United States today are flat-plate collectors, which constitute over 90% of the market. An illustration of the four solar thermal technologies is provided in Figure 8.

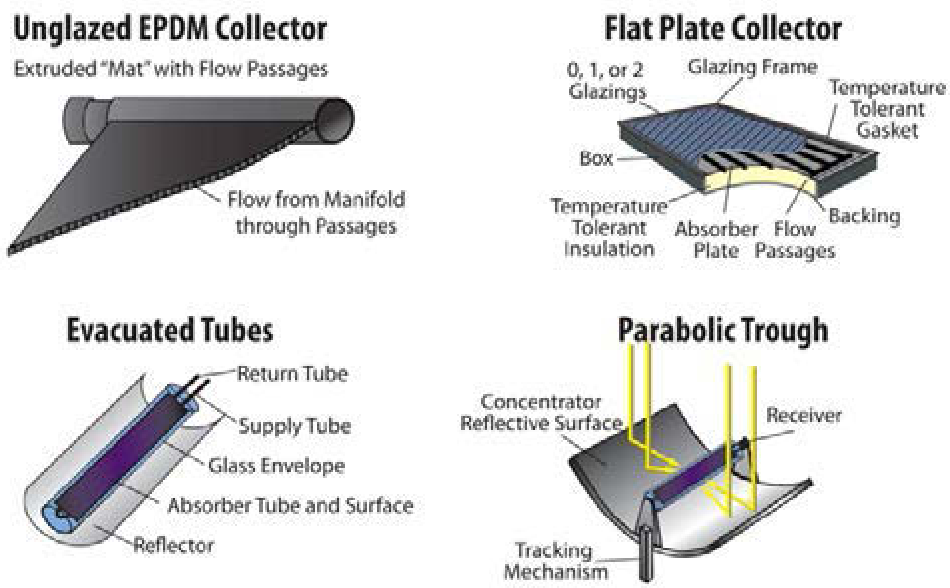

Figure 8. Solar thermal technologies showing unique characteristics

Illustration by Jim Leyshon, NREL

The type of collector that should be used depends on the application and the solution that can provide the lowest life-cycle costs. Low-temperature collectors, such as the unglazed EPDM collectors, are typically used as swimming pool heaters and in residential domestic hot water (DHW) heating applications in hot climates such as Hawaii and Guam. Medium-temperature collectors (flat-plate collectors) are typically used for general DHW heating applications and in cafeterias, laundry facilities, and barracks. High-temperature collectors (evacuated tube and parabolic trough) are typically used in industrial processes. Although evacuated tube collectors are considered a high-temperature collector, they are also commonly applied to many of the same applications as traditional flat-plate collectors. Figure 9 shows that the operational efficiency of each collector is a function of the temperature rise of the collector fluid divided by the incident solar radiation.

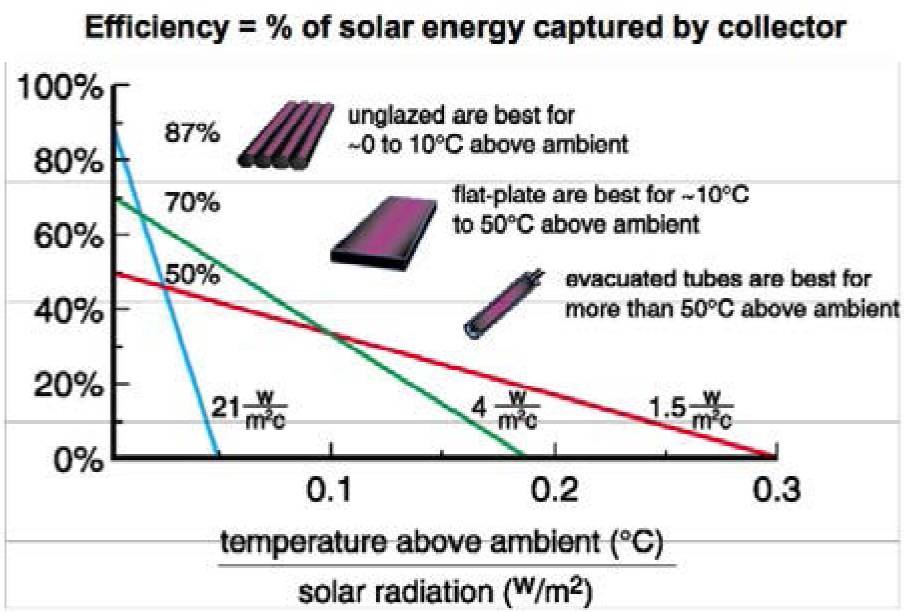

Figure 9. Efficiency of SHW collector as a function of temperature rise[28]

Unglazed collectors have the highest efficiency when operated to provide hot water at temperatures just slightly above the local ambient temperature and each collector's efficiency changes based on the operational temperature above ambient temperature. Unglazed collectors are best for applications where the water only needs to be heated to 0°–10°C (0°–18°F) above ambient, flat-plate collectors are best for 10°–50°C (18°–90°F) above ambient, and evacuated tubes are best for 50°C and above ambient (90°F and above).

Storage Tanks: Storage tanks are typically required to couple the timing of the intermittent solar resource with the timing of the hot water load. Usually, one to two gallons of storage water per square foot of collector area is adequate. Storage can either be potable or non-potable water if a code-approved load-side heat exchanger is used. For conventional small systems, storage is most often in the form of glass-lined steel tanks at line pressure. For large systems, unpressurized storage tanks made of polymers or using polymer liners are common. These can reduce storage cost per unit volume considerably, compared to small pressurized tanks.

Project Development Considerations

Key project development considerations for siting, system design, estimating savings, and policies and permits are presented in this section.

Siting

DHW Fuel Source

The economics of a SHW system are sensitive to fuel source costs, and the cost of electricity on a $/MMBtu basis is typically several times higher than natural gas. As a general rule of thumb, DHW systems that are heated with electric resistance

[28] Walker, A. (September 2012). "Solar Water Heating." Presented at the 7th Annual North American Passive House Conference. Accessed March 2015: http://www.nrel.gov/docs/fy13osti/56706.pdf.

heating elements should be targeted for future SHW installations unless the base is in a location with aggressive SHW incentives and higher natural gas rates.

Facilities with Large Hot Water Loads

Facilities with large, year-round DHW loads should be targeted for SHW installations, and the baseline DHW load should be metered prior to the design of a solar thermal system to ensure that the proposed system is sized correctly. The facility types that should be targeted on DOD bases are swimming pools, barracks, laundry facilities, housing, and kitchens. Lower-water-use facilities, such as offices and administrative facilities, should be considered a lower-level priority.

Distributed Versus Centralized DHW System

Existing facilities with centralized DHW tanks should be targeted for future SHW systems. Existing facilities that have distributed, point-of-use DHW systems should be avoided because the integration costs outweigh any potential energy savings benefits.

SHW Versus PV with Heat Pump Water Heaters

The solar PV industry is among the most dynamic industries in the energy sector and is experiencing revolutionary reductions in installed costs and innovative technology offerings. Due to the liquidity of the market and the pace that new technologies are entering the market, solar PV is more cost effective than SHW systems in many locations. In addition to PV cost reductions, heat pump water heaters have transitioned from an emerging technology to a fully commercial product that can reduce DHW energy use by as much as 64% in certain climates.[29] The combination of onsite PV systems and heat pump water heaters should be compared and contrasted to a SHW system to ensure that a traditional SHW system is the most economical solution for the given application.

DHW System Assessment Guidance

A site assessment of the existing DHW system, end use water loads, and the roof should be conducted to determine if a SHW system is applicable for the given facility. The following characteristics of the DHW system should be recorded:

- Fuel Source: Electric, natural gas, propane, etc.
- Tank Size: Gallons (gal)
- Tank Insulation: R-Value of tank insulation (hr-ft_2-°F/Btu)
- Recirculation Rate: Percent (%)
- Set Point Temp.: Temperature (F°)
- Heating System Eff.: %.

Table 15 can be used to provide a first-pass estimate of daily water usage. Table 15 provides a referenceable estimate of hot water usage per square foot per day and per person per day for different facility types. The water usage per square foot per

[29] Hudon, K.; Sparn, B.; Christensen, D.; Maguire, J. (January 2012). "Heat Pump Water Heater Technology Assessment Based on Laboratory Research and Energy Simulation Models." Preprint. Presented at the ASHRAE Winter Conference, 21-25 January 2012, Chicago, Illinois. Golden, CO: National Renewable Energy Laboratory, 36 pp. Accessed March 2015: http://www.nrel.gov/docs/fy12osti/51433.pdf.

day should be used if the site doesn't have an accurate count of the number of people in the facility, and only one of the two values for each facility type should be used (either gal/ft^2/day or gal/person/day).

Table 15. Hot Water Usage per Person per Day[30]

Building Type	Gal/ft²/Day	Gal/Person/Day
Office	0.00576	5
Mercantile	0.00247	2
Education	0.00987	3
Health Care	0.11594	18
Lodging	0.06948	15
Public Assembly	0.00617	3
Food Service	0.02713	10
Warehouse	0.00288	5
Other	0.00452	5
All Building Average	0.02713	7.5

The water usage for specific activities is provided in Table 16 and can be used for standalone facilities or added to the water usage outlined in Table 15 for mixed-use facilities.

Table 16. Hot Water Usage per Activity per Day

Activity	Average Gallons of Hot Water per Use
Kitchen Meals Served (Per Meal)	1.7
Clothes Washer	7
Automatic Dishwasher	6
Shower	10

Orientation and Tilt

SHW panels should be oriented facing south (in the northern hemisphere) and mounted with a tilt angle that ranges from 0° to latitude. The same orientation and tilt angle guidance that was provided for PV systems also applies to SHW systems.

Shading

Although shading should generally be avoided, SHW panels are not as sensitive to shading as PV systems. An onsite shading assessment should be conducted with a solar pathfinder. If a shading assessment is not available, select a location that is

[30] Source for Table 15 and Table 16:
Walker, A. (2013). *Solar Energy: Technologies and Project Delivery for Buildings*. Wiley. 320 pp.: http://www.wiley.com/WileyCDA/WileyTitle/productCd-1118139240.html.

unshaded from 9 a.m. to 3 p.m. If there is partial shading on a proposed SHW location, an economic analysis should be conducted to ensure that the system is still cost effective.

Historical Considerations

The same historical considerations that apply to PV systems also apply to SHW systems.

Building Structural Integrity

SHW systems typically add a dead load of 2–5.5 lb/ft^2 to the roof, and the engineering department should be contacted to flag any facilities with known structural integrity issues prior to moving forward with siting a SHW system. In general, the same building structural integrity considerations that apply to PV systems also apply to SHW systems.

Roof Age and Condition

SHW systems will last for up to 25 years, and SHW systems should be installed on roofs that have a useful life of at least 25 years. The engineering department should be consulted to determine the age and condition of each roof, and any roof that needs to be replaced or re-roofed should do so prior to the installation of a SHW system. If this is the case, then SHW system installations can be staged to occur after the re-roofing schedule for selected facilities.

System Design

Implement Efficiency First

The existing DHW equipment should be analyzed prior to the installation of a SHW system, and all applicable water conservation and energy efficiency opportunities should be implemented prior to the sizing of a solar thermal system. Low-flow faucets, low-flow shower heads, ENERGY STAR washing machines, and energy-efficient kitchen equipment can reduce hot water loads by 50% or more, and the implementation of water reduction measures prior to the installation of a SHW system helps to reduce the size of the SHW system and also ensures that all the solar energy produced by the SHW system is used to heat DHW. If the system is grossly oversized after water reduction measures are implemented, then the excess solar energy will need to be discharged to the atmosphere via heat dump radiators, which will hurt the overall economics of the system.

Equipment Selection

In general, the site does not need to undergo the process of specifying certain SHW panels or storage tanks prior to submitting an ECIP application. The system should be sized based on the hot water load and that information can be provided to solar installers when the project is competitively bid out.

Metering

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the MDMS. Sub-metering should be installed and used to report the thermal energy production and to compare to predicted energy production on a monthly basis. At a minimum, BTU meters should be installed on either the solar thermal loop or the outlet of the solar thermal storage tank to measure the total solar thermal energy production each month. BTU meters record entering water temperature, leaving water temperature, and flow rate.

Estimating Savings

Equipment Lifetime

SHW panels typically have shorter warranties than PV panels, but the equipment should still be evaluated assuming a 25-year lifetime. The small circulation pumps will typically need to be replaced at least once over a 25-year period, but with standard maintenance protocols, the tanks, panels, and piping should last for 25 years in most non-marine climates. If the site is located next to the ocean, the project lifetime should be derated based on onsite personnel's' or local installers' experience with similar projects.

Policies and Permits

The site should contact the local utility to obtain a list of any local incentives or policies regarding SHW installations.

Estimating SHW Capital Costs and O&M Costs

Capital Costs

NREL's Energy Technology Cost and Performance Data for Distributed Generation website[31] currently estimates a flat-plate SHW system averages $141/square foot, with a range of approximately $60–$220/square foot.

O&M Costs

For economic analysis, an annual O&M cost of 0.5%–1.0% of the initial installed cost is typically used.

Estimating Energy Production

Energy production can be estimated with one of the following free software tools:

- RETScreen: http://www.retscreen.net
- Solar Advisor Model: https://sam.nrel.gov.

RETScreen is the simpler of the two software tools and is the focus of this guide.

Example Calculation

A two-story barracks facility at a military base in Albany, New York, is being investigated as a potential host site for a solar hot water system. The facility is oriented slightly east of south. Note that RETScreen uses a different azimuth angle for south-facing arrays than PVWatts. Figure 10 explains how azimuth angle is calculated in RETScreen.

[31] NREL Energy Technology Cost and Performance Data for Distributed Generation. Accessed March 2015: http://www.nrel.gov/analysis/tech_cost_data.html.

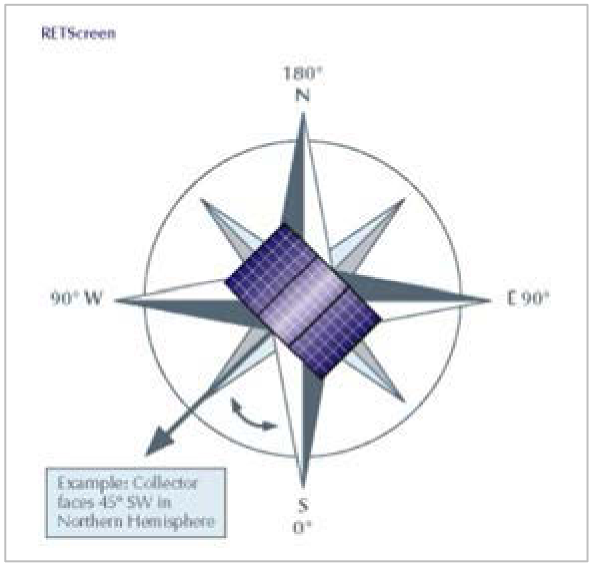

Figure 10. RETScreen azimuth angle reference

Source: www.retscreen.net

The azimuth angle for an array located on the roof of this facility would be -15°. Panels that are mounted east of south are entered using a negative notation in RETScreen, and panels that are mounted west of south are entered using a positive notation. The area available from the two highlighted areas in Figure 11 is 2,312 ft^2 and was calculated using the ruler tool in Google Earth. If additional roof area is needed, there are additional sections of the roof that could be used for SHW or PV.

SOLAR HOT WATER

Figure 11. Potential SHW locations on barracks roof

Image credit: © Google Earth 2014, alterations Jesse Dean

The facility can house approximately 150 cadets, and the occupancy rate is approximately 91% (~136 cadets). The DHW is provided by two 750 MBH natural-gas-fueled hot water boilers with a rated efficiency of 85%. A large 1,950-gal storage tank supplies hot water to the facility, and the tank set point temperature is 140°F. The following information was input into RETScreen version 4.

On the Start tab:

- Project Type: Heating
- Technology: Solar Hot Water
- Analysis Type: Method 1

  Method 1 includes simpler financial analysis and should be selected for ECIP projects, as a separate financial analysis is conducted in the ECIP form.
- Heating Value Reference: Higher Heating Value *(use as default)*
- Climate Data: Albany, New York.

On the Energy Model tab:

Load Characteristics

- Application: Hot Water
- Load Type: Hotel/Motel *(Base Case)*
- Number of Units: 150
- Occupancy Rate: 91%
- Daily Hot Water Use: 2,040 gal/day *(based on 136 residents x 15 gal/day/person Proposed and Base Case)*
- Temperature: 140°F *(Proposed and Base Case)*
- Operating Days Per Week: 7 days *(Proposed and Base Case).*

Percent of Month Used

- Supply Temp. Method: Formula.

Resource Assessment

- Solar Tracking Mode: Fixed
- Slope: 15° *(assumes standard roof mount)*
- Azimuth: -15° *(facing just east of south).*

Solar Water Heater

- Solar Water Heater Type: Glazed *(typical flat-plate collector)*
- Manufacturer: Soltec *(arbitrarily selected)*
- Model: Ligna
- Number of Collectors: 49 *(based on RETScreen recommendation to right of input)*
- Calculated System Size: 1,378 ft^2
- Miscellaneous Losses: 5% *(can be used as generic value).*

Balance of System and Miscellaneous

- Storage Tank: Yes
- Storage Capacity: 1.5 gal/ft^2 *(use as default value)*

- Heat Exchanger: No *(use as default value)*
- Miscellaneous losses: 5% *(can be used as generic value)*
- Pump Power: 0.5 W/ft^2 *(typical range is 0.35–2 W/ft^2, with larger commercial Systems having lower values).*

Heating System

- Fuel Type: Natural Gas *(Proposed and Base Case)*
- Seasonal Efficiency: 85% *(Proposed and Base Case)*
- Fuel Rate: \$7.49/MMBtu *(Proposed and Base Case)*[32]
- Energy Savings: 262.7 MMBtu/yr *(RETScreen output)*
- Energy Cost Savings: \$1,968/yr *(RETScreen output).*

Initial Cost

- Other: \$142,212 (\$140/ft^2 x 1.1 x 1,378 ft^2 of collector area) - \$70,000 *(Assumes \$70,000 capacity-based incentive is available).*

Annual Costs and Debt Payments

- O&M Costs: -\$2,122/yr *(1% x \$212,212).*

For this case, the simple payback using the RETScreen financial tools is more than 100 years, which is beyond the allowable payback period for ECIP projects. If the same analysis were run assuming the facility had electric hot water heaters with an efficiency of 90% and an electric rate of 16.37 cents/kWh,[33] the annual energy savings would be 72,800 kWh/yr, the energy cost savings would be \$11,906/yr, and the new simple payback is 16.98 years using the RETScreen financial metrics. This clearly illustrates that the fuel cost has a huge impact on overall economics and that a system will rarely be cost effective with natural gas backup without some local incentives. Even with high utility rates, you may need some local incentives or low installed costs to make the economics work.

[32] Statewide average natural gas rate for commercial customers: "Natural Gas Prices." (2015). U.S. Energy Information Administration. Accessed March 10, 2015: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SNY_m.htm.

[33] Statewide average electric rate for commercial customers: "Electric Power Monthly." (2015). U.S. Energy Information Administration. Accessed March 10, 2015: http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a.

The information was entered into the ECIP form for the system with electric backup, and Table 17 outlines the economic parameters of the SHW system.

Table 17. SHW Example, Economic Parameters

Parameter	Value	Notes
Installed Cost	$140/ft^2 of collector area	From: http://www.nrel.gov/analysis/tech_cost_dg.html
O&M Cost	1% of capital cost	From: http://www.nrel.gov/analysis/tech_cost_dg.html
Analysis Period	25 years	
Energy Savings	248.4 MMBtu	[(72,800 kWh/yr x 3,412 Btu/kWh) / (1,000,000 MMBtu/Btu)] = 248.4 MMBtu
Electric Rate	$0.1637/kWh	Blended rate includes both electric rate and demand rate
Federal Tax Incentive	$0.00	As this will be purchased by the agency
Capacity-Based Incentive	$70,000	Assumes a local incentive will cover $70,000 of the total installed costs
Production-Based Incentive	$0.0/kWh	Assumes no local incentives

The installed cost should be adjusted to account for an estimated government cost premium of 10%. The investment costs as outlined in the ECIP form are shown in Table 18 below.

Table 18. SHW Example, Investment Costs

Parameter	Value	Notes
Construction Cost	$212,212	($1.4/ft^2 x 1.1 x 1,378 ft^2 of collector area) = $212,212
SIOH (5.7%):	$12,096	Calculated automatically in ECIP worksheet
Design Cost (4%)	$8,488	Calculated automatically in ECIP worksheet. However, most of the quoted prices for RE already include design costs, so energy managers should consider removing the additional 4% design cost for their project or reducing the construction cost estimate by 4% so that design costs are not counted twice.
Salvage Value of Existing Equipment	$0	
Public Utility Company Rebate	-$70,000	Local incentive for $70,000
Total Investment	$162,797	Calculated automatically in ECIP worksheet

The energy savings are input into the ECIP form as shown in Table 19 below.

Table 19. SHW Example, Energy Savings in ECIP Form

Parameter	Value	Notes
Electric Cost	$47.98/MMBtu	$0.1637/kWh/3,412 Btu/kWh x 1,000,000 MMBtu/Btu = $47.98/MMBtu
Energy Savings	248.4 MMBtu/yr	
Annual Savings	$11,918	Calculated automatically in ECIP worksheet
Discount Factor	17.1	Based on 25-year discount factor for electricity in New York
Discounted Savings	$203,802	Calculated automatically in ECIP worksheet
Total Savings	$203,802	Calculated automatically in ECIP worksheet

The non-energy costs are input into the ECIP form as shown in Table 20 below.

Table 20. SHW Example, Non-Energy Costs and Savings in ECIP Form

Parameter	Value	Notes
Annual Recurring	($2,122)	1% x $212,212 = -$2,122
Discount Factor	17.41	Based on discount factor for finding the present value of annually recurring uniform costs (non-fuel)
Discounted Cost	($36,946)	Calculated automatically in ECIP worksheet

The system economics are summarized in the ECIP form as shown in Table 21 below.

Table 21. SHW Example, Summary in ECIP Form

Parameter	Value	Notes
First-Year Dollar Savings	$9,796	Calculated automatically in ECIP worksheet
Simple Payback	16.6	Calculated automatically in ECIP worksheet
Total Net Disc. Savings	$166,856	Calculated automatically in ECIP worksheet
SIR	1.02	Calculated automatically in ECIP worksheet

For this example, the SIR is slightly above 1, so the project would need to score well in all of the non-energy savings/economics categories to be approved.

Training

FEMP offers two general RE trainings via webinar that include modules on SHW:

- Introduction to Renewable Energy Technologies: http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=20
- Distributed-Scale Renewable Energy Projects: From Planning to Project Closeout: http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=2188.

Army Bases That Have Successfully Installed SHW Funded by ECIP

Schofield Barracks has successfully installed onsite SHW systems (Table 22).

Table 22. SHW System Base Contact

Name	Base	Title	Phone	Email
Keith Yamanaka	Schofield Barracks	Energy Manager	215-446-4769	keith.k.yamanaka.civ@mail.mil

SOLAR VENTILATION PREHEATING

Technology Description

Solar ventilation preheating (SVP) uses solar radiation to preheat ventilation air. SVP is a simple and efficient technology that is used to heat building ventilation air during the heating season. A diagram of a typical SVP system is shown in Figure 12.

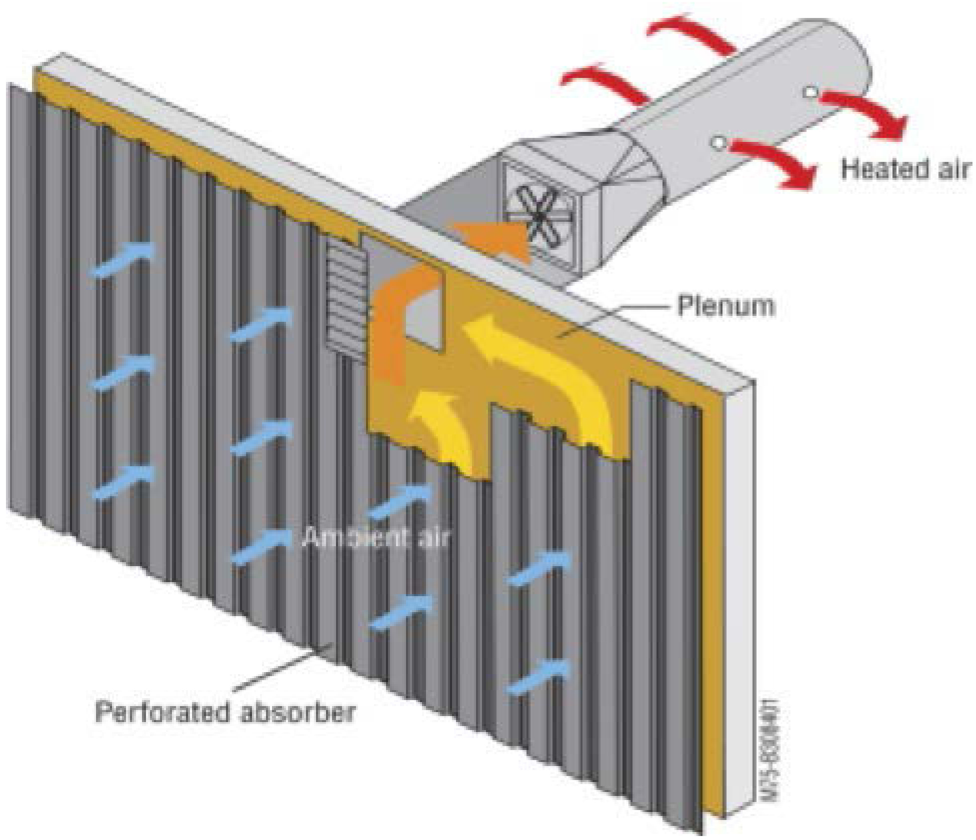

Figure 12. SVP system[34]

The process of solar ventilation air preheating begins when incident solar radiation warms the transpired solar collector. This is a wall constructed of perforated metal panels 4 feet wide and any length. The collector is perforated with tiny holes and painted a dark color to absorb maximum solar radiation.

The transpired collector is secured to the south-facing wall by mounting brackets that stand the transpired collector away from the wall to create a 4–6 inch plenum, or space, to retain the preheated ventilation air. Like all metal siding, the collector and mounting brackets must withstand wind loads in the 90–110 mph range for most areas and as high as 150+ mph for areas with hurricane potential.

[34] Transpired Air Collectors: Ventilation Preheating (Fact sheet). (2006). U.S. Department of Energy. FS-550-29913; DOE/GO-102001-1288. Accessed March 2015: http://www.nrel.gov/docs/fy06osti/29913.pdf.

The ventilation air is drawn through the holes in the collector and into the plenum by the action of a ventilation fan, which typically already exists in a building. The solar radiation heats the air in the plenum as it is drawn into the building. Stub duct, fabric duct, or existing ductwork can be used to distribute hot air from the solar ventilation preheating system directly into a space heated by other means, such as unit heaters. But more likely, the solar preheated air would be ducted to the first stage of an air handling unit. This first stage would have an actuated bypass damper on the duct from the solar ventilation preheat collector as well as one on the outside air damper. These dampers would be controlled such that when the space is calling for heat, the outside air damper would be closed and the solar ventilation preheat damper would be open. If the space does not need the heat, the outside air damper would be open and the solar ventilation preheat damper would be closed.

Project Development Considerations

Key project development considerations for siting are presented in this section.

Siting

Climate Zone

As this is a heating technology, the economics of the system are significantly impacted by the number of heating degree days at the given location. For example, locations that require heating for at least 8 months per year will have much better economics than locations that only require heating for 3 or 4 months per year.

Building Orientation

Solar ventilation preheat systems should ideally be designed and installed in a position that faces within 45° of true south (for the northern hemisphere) to maximize solar energy collection. The solar ventilation preheat collector should not be positioned near sources of pollution such as truck bays. A large, unshaded south-facing wall to support the solar ventilation preheat collector is ideal.

Building Type

Vehicle maintenance facilities and other industrial buildings that require a constant amount of ventilation air and match well with the aesthetic of metal siding are ideal applications of this technology. Commercial buildings are often closed on weekends and holidays, which reduces the energy savings of this technology, as there is no way to store preheated ventilation air.

Heating System

Careful attention should be paid to the outside air requirements of the target facility. Outside air only makes up a fraction of the air supplied by typical HVAC systems, and HVAC systems with high outside airflow rates are good candidates. Heating systems that are currently heated with electric resistance heating units or other expensive fuels such as electricity, oil, or propane are also good applications. When siting an SVP system, the location of the outside air ductwork and rated flow rate need to be noted. Facilities with outside air intakes on the south side of the facility are ideal, and the distance from the SVP panels to the outside air intake needs to be taken into account when calculating installed costs. If the outside air intake is too far from the south wall, it will increase both installed costs and fan power to overcome the pressure drop. System manufacturers should be consulted if a specific facility is in question due to the distance to the outside air intake.

Exhaust Air Heat Recovery

A facility that already has available or planned heat recovery from exhaust air—from an air-to-air heat exchanger, run-around glycol loop, or rotating enthalpy wheel—may have a lower-cost way to preheat ventilation air 24 hours a day. This would reduce the savings expected from an SVP system and thus its economic viability.

Internal Heat Gains

A building that is not already heated by internal gains (for example, many computers or other equipment that give off heat and require year-round cooling) is preferred for this technology.

Metering

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the MDMS. Sub-metering should be installed and used to report the total thermal energy supplied to the space. BTU meters are available which combine measurements of plenum or duct temperature (downstream of the SVP system), outside air temperature, and air flow rate to directly measure delivered energy. If the airflow rate does not change (i.e. for constant speed fan systems), then a one-time measurement of airflow is sufficient and fan status (on-off) is used as a proxy for air flow measurement. For small systems, for which cost savings are small, air flow rate may be stipulated based on one-time capture hood or duct air flow measurement or design calculations, and the BTU calculation can be performed in the MDMS based only on the temperature measurements. The result of the BTU measurement should be tied into the Building Automation System (BAS) and used to track energy production.

Estimating SVP Capital Costs and O&M Costs

Capital Costs

NREL's Energy Technology Cost and Performance Data for Distributed Generation website[35] estimates an SVP system averages $31/square foot, with a range of approximately $16–$46/square foot.

O&M Costs

SVP systems consume between 0.1 W/ft^2 and 0.7 W/ft^2 of collector area to power the SVP fan. SVP systems typically require little to no annual maintenance, and therefore for economic analysis, annual O&M costs are typically assumed to be $0/yr.

Equipment Lifetime

SVP systems are one of the simplest RE technologies, and since the collector is made of perforated metal panels, it is less prone to failure than other RE technologies. The project should be analyzed using a 30-year project lifetime.

Estimating Energy Production

Energy production can be estimated with RETScreen: http://www.retscreen.net. Appropriate RETScreen inputs are described in the example below.

[35] NREL Energy Technology Cost and Performance Data for Distributed Generation. Accessed March 2015: http://www.nrel.gov/analysis/tech_cost_data.html.

Example Calculation

A 39,000-ft^2 steel-framed uninsulated fuel storage facility with Transite external panel walls and concrete and wood frame internal walls is being considered for an SVP system. This facility houses 38 separate electric heater units that maintain an internal temperature of 70°F during the winter months. The building does not have air conditioning. The SVP would be connected to simple fabric distribution ducting inside the building.

Figure 13. Fuel storage facility SVP example

Image credit: © 2014 Google Earth, alterations by Otto Van Geet

The building is continuously exhausted at a rate of 6,600 cubic feet per minute (CFM) and uses electric heat at a rate of \$0.08/kWh. The facility is nearly ideal for SVP because the long axis of the building faces south, and the site is located in a colder climate that requires a significant amount of heating during the winter months. Given the wall dimensions in Figure 13, there is approximately 8,000 ft^2 of wall area that could be used for an SVP installation.

SOLAR VENTILATION PREHEATING

The following information was input into RETScreen version 4.

On the Start tab:

- Project Type: Heating
- Technology: Solar Air
- Analysis Type: Method 1

  Method 1 includes simpler financial analysis and should be selected for ECIP projects, as a separate financial analysis is conducted in the ECIP form.

- Heating Value Reference: Higher Heating Value
- Climate Data: Idaho Falls Fanning Field.

  On the Start tab, the wind speed reported in RETScreen is measured at 10 m (30 ft) and the wind speed is lower closer to the ground level of the facility. If the solar wall is installed at a height of fewer than 30 feet, it should be derated by 70%. For this facility the wind speed was reduced by 30%.

On the Energy Model tab:

Load Characteristics

- Application: Ventilation
- Facility Type: Industrial
- Indoor Temperature: 70°F
- Minimum Air Temperature: 30°F
- Maximum Air Temperature: 100°F
- Indoor Temp. Stratification: 0°F

  This input has a significant effect on estimated annual energy savings. Unless there is a known stratification issue and the site is planning on installing a de-stratification fan as a part of the installation, this should be input as 0°F.

- Floor Area: 39,000 ft^2
- R-Value – Roof: 1.7 ft^2 - ft^2 ºF/(Btu/h)
- R-Value – Walls: 1.4 ft^2 - ft^2 ºF/(Btu/h)

Roof and wall R-values are based on the construction materials used in the walls and roof and are a measurement of heat loss per unit area of wall or roof area based on the temperature difference between the inside and outside surface of the wall or roof. This information should be collected via the site visit. R-values range from 1 for non-insulated brick walls to as high as 30 or 40 for highly insulated walls and roofs. The R-values for this facility are poor and are indicative of a facility that is not insulated or has very little insulation.

- Design Airflow Rate: 6,600 CFM
- Operating Days/Week: 5
- Operating Hours/Day: 12
- Operating Days/Week: 2 (weekend)
- Operating Hours/Day: 0 (weekend).

Percent of Month Used

- January – May: 100%
- June – September: 0%
- October – December: 100%.

These systems are typically shut down during summer months, and for this example it is assumed that it is shut down from June through September. Energy managers should evaluate their local weather file to determine which months per year the system will be shut down.

Resource Assessment

- Solar Tracking Mode: Fixed
- Slope: 90°

Most installations are vertical, and in this case all would have a 90° slope.

- Azimuth: 0°.

SOLAR VENTILATION PREHEATING

Solar Air Heater

- Solar Air Heater Type: Transpired - plate
- Manufacturer: Conserval Engineering *(one of the main product manufacturers)*
- Model: Solarwall - Black
- Solar Collector Area: 3,353 ft^2 *(based on RETScreen recommendation)*
- Solar Collector Shading: 0%
- Incremental Fan Power: 0.1 W/ft^2

  (Use as default; this value can range from 0.1–0.7 W/ft^2 depending on configuration and distance to the outside air intake)
- Electricity Rate: $0.080/kWh.

Heating System

- Fuel Type: Electricity (Proposed and Base Case)
- Seasonal Efficiency: 100% (Proposed and Base Case)
- Fuel Rate: $0.080/kWh (Proposed and Base Case)
- Energy Savings: 148,600 kWh/yr (RETScreen output)
- Energy Cost Savings: $11,893/yr (RETScreen output).

Initial Cost

- Other: $124,732 ($30/ft^2 x 1.2 x 3,353 ft^2 of collector area).

In this example, RETScreen estimates 3,353 ft^2 of SVP could be installed on the south side of the facility, which has an available south wall area of up to 8,000 ft^2. The expected cost is approximately $124,732, with an expected savings of $11,893/yr and a simple payback of 10.5 years. The amount of collector area typically ranges from 2–5 CFM/ft^2. In this example, if the SVP area is reduced to 1,556 ft^2, the economics improve slightly because of the higher overall flow rate, and the capital costs also go down by almost 50%—but the total savings decrease as well. If the site is interested in maximizing energy savings, it should install a larger system, but if it wanted to minimize life-cycle costs, it should install the smaller system. The site is encouraged to adjust the recommended square footage of collector area to help determine the best payback for the given location. If the site proceeds with an SVP project, it is recommended to work with a vendor with experience in both the design and installation of SVP systems to ensure the system is sized correctly.

It should also be noted that if this same facility were heated by a natural gas heating system with 80% efficiency, the payback would be 28.5 years and would not be cost effective in this location and application. Again, fuel source and heating system type have a big impact on economics.

Table 23 outlines the ECIP form economic parameters for the SVP system in this example.

Table 23. SVP Example, Economic Parameters

Parameter	Value	Notes
Installed Cost	$\$30/ft^2$ of collector area	From: http://www.nrel.gov/analysis/tech_cost_dg.html
Analysis Period	30 years	
Energy Savings	507 MMBtu	[(148,600 kWh/yr x 3,412 Btu/kWh) / (1,000,000 MMBtu/Btu)] = 507 MMBtu
Electric Rate	$0.08/kWh	Blended rate includes both electric rate and demand rate
Federal Tax Incentive	$0.00	Because this will be purchased by the agency
Capacity-Based Incentive	$0.00	
Production-Based Incentive	$0.00/kWh	Assumes no local incentives

The installed cost should be adjusted to account for an estimated government cost premium of 10%. The investment costs as outlined in the ECIP form are shown in Table 24 below.

Table 24. SVP Example, Investment Costs

Parameter	Value	Notes
Construction Cost	$110,649	($\$30/ft^2$ x 1.1 x 3,353 ft^2 of collector area) = $110,649
SIOH (5.7%):	$6,307	Calculated automatically in ECIP worksheet
Design Cost (4%)	$4,426	Calculated automatically in ECIP worksheet. However, most of the quoted prices for RE already include design costs, so energy managers should consider removing the additional 4% design cost for their project or reducing the construction cost estimate by 4% so that design costs are not counted twice.
Salvage Value of Existing Equipment	$0	
Public Utility Company Rebate	$0	
Total Investment	$121,382	Calculated automatically in ECIP worksheet

Energy savings are input into the ECIP form as shown in Table 25 below.

Table 25. SVP Example, Energy Savings in ECIP Form

Parameter	Value	Notes
Electric Cost	$23.45/MMBtu	$0.08/kWh / 3,412 Btu/kWh x 1,000,000 MMBtu/Btu = $23.45/MMBtu
Energy Savings	507 MMBtu/yr	
Annual Savings	$11,889	Calculated automatically in ECIP worksheet
Discount Factor	19.98	Based on 30-year discount factor for electricity in Idaho
Discounted Savings	$237,545	Calculated automatically in ECIP worksheet
Total Savings	$237,545	Calculated automatically in ECIP worksheet

There are no non-energy costs or savings for this SVP system because O&M costs are estimated at $0 and there are no incentives.

The system economics are summarized in the ECIP form as shown in Table 26 below.

Table 26. SVP Example, Summary in ECIP Form

Parameter	Value	Notes
First-Year Dollar Savings	$11,889	Calculated automatically in ECIP worksheet
Simple Payback	10.2	Calculated automatically in ECIP worksheet
Total Net Disc. Savings	$237,545	Calculated automatically in ECIP worksheet
SIR	1.96	Calculated automatically in ECIP worksheet

For this example, the SIR is greater than 1, and the project would also need to score well in all of the non-energy savings/economics categories to be approved.

Training

FEMP offers general RE training via a webinar that includes a module on SVP:

Introduction to Renewable Energy Technologies:
http://apps1.eere.energy.gov/femp/training/course_detail_ondemand.cfm/CourseId=20

Additionally, a DOE fact sheet and more detailed report are available on SVP:

- Transpired Air Collectors Ventilation Preheating fact sheet: http://www.nrel.gov/docs/fy06osti/29913.pdf
- Federal Technology Alert – Transpired Collectors (Solar Preheaters for Outdoor Ventilation Air): http://www1.eere.energy.gov/femp/pdfs/fta_trans_coll.pdf.

Army Bases That Have Successfully Installed SVP Funded by ECIP

Fort Carson and Fort Drum have successfully installed SVP systems (Table 27).

Table 27. SVP System, Base Contact

Name	Installation	Title	Phone	Email
Scott Clark, CEM	Ft. Carson	Energy Manager	(719) 526-1739	scott.b.clark.civ@mail.mil
Stephen Rowley	Ft. Drum	Energy Manager	(315) 772-5433	stephen.e.rowley3.civ@mail.mil

GROUND-SOURCE HEAT PUMPS

Ground-source heat pump (GSHP) systems, also referred to as geothermal heat pump or geoexchange systems, are a space heating and cooling technology that takes advantage of the relatively constant temperature of the earth's subsurface below certain depths to provide building space conditioning (i.e., the subsurface is a source of heat in the winter and an efficient heat rejection medium in the summer). On the system level, GSHP systems are a clean, energy-efficient technology that can effectively replace conventional heating and cooling technologies.

Technology Description

GSHP systems are comprised of two main components: the interior mechanical system and the exterior loop field, also referred to as a ground/water heat exchanger (HE).

Interior System

Interior equipment consists of the heat pumps and the heating, ventilation, and air-conditioning (HVAC) distribution system. Heat pumps are devices that move thermal energy by absorbing heat from a warm space and releasing it into a colder one, and vice-versa (Figure 14). A heat pump uses some amount of external power to accomplish the work of transferring energy from the heat source to the heat sink. This is accomplished by compression or absorption. Compression heat pumps operate on mechanical energy (typically driven by electricity), while absorption heat pumps run on heat as an energy source (electricity or fossil fuel). In terms of heating, heat pumps are more efficient than conventional fossil-fuel-based technologies, with coefficient of performance (COP) values in the range of 3–5 (typically 4) vs. less than 1 for conventional systems. In terms of cooling, heat pumps have seasonal energy efficiency ratings (SEERs) ranging from 14–28 (typically 18, which equates to a COP for cooling of about 5.0), which is better than most air-cooled chillers and air-conditioning equipment.

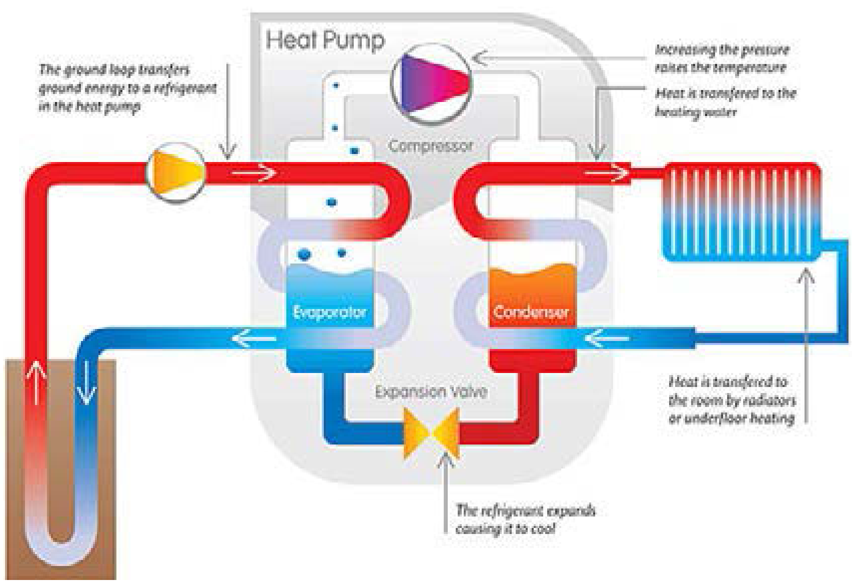

Figure 14. Schematic showing how GSHP technology works

Illustration by Erin Anderson, NREL

Heat pumps can be connected to almost any type of HVAC distribution system, but they work best in hydronic and forced-air systems. Hydronic systems, often referred to as radiant floor systems, are comprised of flexible pipes embedded in the floor. They can also be installed in the walls or ceiling if the floors are wood or carpet-covered. Forced air delivery is also a common HVAC distribution system configuration for GSHPs.

Exterior System

Loop Field

In general, GSHP systems are more efficient (i.e., higher COP and SEER) than other types of heat pump systems (e.g., air-source, exhaust air, etc.) because they can take advantage of relatively constant temperatures found below certain depths in the earth's subsurface. This is accomplished by installing a loop field, or ground/water HE, to provide a heat source/sink for the heat pump. Loop fields have a number of configurations and can be open or closed loop (see Figure 15). The type (i.e., open or closed) and configuration (i.e., vertical, horizontal, or surface water) utilized in a GSHP system is based on land availability, accessibility to surface/ground water, and subsurface parameters: thermal conductivity, thermal diffusivity, and *in situ* temperature.[36]

[36] Thermal conductivity (BTU/h-ft-°F) is the ability of a medium to transport heat. Thermal diffusivity (ft^2/day) is the ratio of heat transport ability to heat storage capacity; the higher the value, the more rapidly temperatures can change. *In situ* subsurface temperature (°F) is the average temperature of medium at depth.

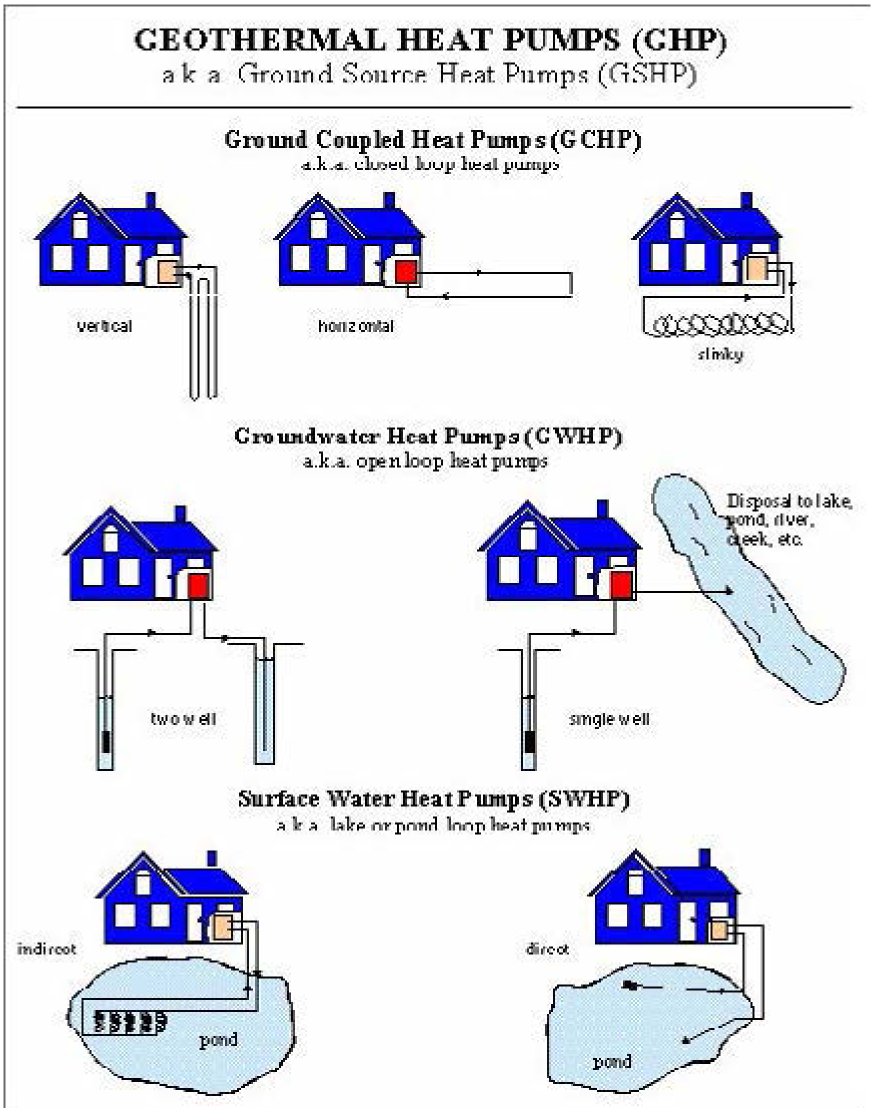

Figure 15. Examples of GSHP loop field types[37]

Credit: Illustration from the Oregon Institute of Technology

The size of the loop field is a function of building heating/cooling load (a function of building use and envelope quality and local climate) and subsurface conditions (described previously). Proper design and installation of the loop field is critical to the overall performance of the GSHP system, as it can strongly affect system performance.

Open-Loop Systems

Open-loop systems can be installed where groundwater is readily accessible and/or where surface water (e.g., river, stream, lake, or pond) can be accessed. Water is typically pumped through a plate heat exchanger to mitigate fouling of the heat

[37] Source: The Geo-Heat Center's *Survival Kit for the Prospective Geothermal Heat Pump Owner*, http://geoheat.oit.edu/ghp/survival.pdf.

pump before being discharged or re-injected (see Figure 15). In rare cases, where the groundwater or surface water is exceptionally clean, water can be pumped directly through the heat pump.

Closed-Loop Systems

Closed-loop systems circulate a fluid (typically a water-antifreeze mixture such as glycol) through high-density polyethylene (HDPE) pipe. Closed-loop systems are installed in areas where groundwater or open water is either inaccessible or not permissible. Closed-loop HEs can be installed horizontally, vertically, or in surface water.

Horizontal Loop Fields

Horizontal HEs come in the form of large areal excavations (pits) or trenches, where pipe is laid out linearly or in slinky form (Figure 16). Horizontal HEs are closed-loop and need to be installed at a depth sufficient to minimize the seasonal influence of solar irradiance on the subsurface. Typically horizontal HEs are installed at depths between 4 and 8 feet below the ground surface (depending on climate and soil properties). Horizontal HEs can require significantly more land area disturbance for installation relative to vertical HEs; however, they can be installed under parking lots, athletic fields, within landfill caps, etc.

Figure 16. Examples of horizontal loop fields: A) areal linear; B) areal slinky; C) trench, horizontal slinky; and D) trench, vertical slinky
Photos from Major Geothermal

Vertical Loop Fields

Vertical HEs are comprised of a single borehole, or a series of boreholes, and can be open or closed (see Figure 15). In an open-loop vertical HE, one or more boreholes are completed in an appropriate water-bearing formation (i.e., aquifer), and water is produced from the formation and then discharged or re-injected after passing through the heat exchanger/heat pump.

In a closed-loop vertical HE, u-shaped HDPE pipe is installed and grouted in place in each borehole. The number of boreholes and their spacing and depth are dependent upon the length of loop needed to service the building load, which is, in turn, a function of the subsurface parameters.

Surface Water

Surface-water HEs can either be open or closed loop and can be placed in ponds, lakes, rivers, wetlands, and even oceans.[38] Similar to a horizontal HE, the inlet or loop must be placed at a depth at which the influence of seasonal changes in near-surface water temperature (including icing) and fluctuations in water level (and in the case of tidally-influenced areas, diurnal fluctuations) are mitigated. More often than not, GSHP systems utilizing ponds or lakes deploy closed-loop systems, either HDPE pipe coiled in cages or metal-plate HEs.

New Loop Field Concepts

More recent innovations have resulted in a number of building-integrated closed-loop HE concepts. Examples include the integration of HDPE pipe into support piers for buildings and bridges, or building foundations with the pipe intertwined in the rebar superstructure. In both cases, these concepts are only applicable to new construction.

Project Development Considerations

Key project development considerations for siting, system design, estimating savings, and policies and permits are presented in this section.

Siting

Building Type and Usage

The Army employs a variety of building types to service its needs. Although GSHP systems can work on most any facility as long as thermal load profiles for heating and cooling are known and land is available for installation of the loop field, packaged single-zone (PSZ) HVAC systems are typically the easiest to retrofit and should be targeted for GSHP retrofits. Larger commercial buildings with central boilers, chillers, and air handling units are typically more complex to retrofit and tend to have higher baseline heating and cooling efficiencies. In addition, DOD facilities that are currently heated with steam should be avoided unless the facility is going through a full facility modernization and the steam system is being replaced with a hot water distribution system. The quality of a building's envelope is also important with regard to energy savings and system sizing. It is highly recommended that the building envelope be evaluated and upgraded to current standards prior to designing and installing a new heating and cooling system (whether it be GSHP or some other type) in order to improve thermal comfort within the facility and reduce the size and cost of the proposed GSHP system.

Climate

Aside from building type and usage, climate plays a key factor in determining building thermal load and the "shape" of the heating and cooling profiles. Climate regimes can be cooling- or heating-dominant or balanced. GSHPs work best in balanced climate regimes, but are flexible enough to work over a broad range of climates. GSHPs can also be hybridized (discussed below) to work effectively in cooling or heating dominant climate regimes.

In some cases, even though local climate indicates a balanced heating and cooling load, a given building may be heating or cooling dominant. This is why a complete and thorough estimation of building thermal demand is necessary for the design of an HVAC system.

[38] There are very few examples of river or ocean installations due to strong current, tidal influences, and/or wave action.

Hybrid Systems

One way to overcome GSHP limitations with heating- or cooling-dominated thermal loads is to hybridize the system with other technologies. These technologies can be simple or complex. For example, in a heating dominated situation, adding a boiler to augment the system is common; in a cooling dominated situation, the addition of a cooling tower is typical. GSHP systems can also be hybridized with technologies that may provide a beneficial use such as snow melting or ice making.

New Construction vs. Retrofit

Planning the installation of a GSHP system in a new building is much less complex than retrofitting it into an existing building. In a new facility, the interior heating and cooling distribution system can be designed for the desired internal zoning and heat pump configuration, while in retrofit situations the reworking of the existing heating and cooling distribution system can be complex and expensive. For example, buildings with steam heating will require the removal of all or part of those systems and replacement with either hydronic or forced air systems. Buildings with forced air systems may require some ductwork resizing to accommodate the GSHP system, or will need to be coupled with an onsite boiler to provide hot enough hot water to the existing heating coils.

Mission Impact

GSHP systems will have no impact on mission, except for possibly during the installation phase. Dust and noise from site preparation, demolition, and system installation are those associated with typical building construction and/or remodeling efforts. The primary difference will be the temporary land disturbance associated with the installation on the loop field, which could require traditional construction equipment (i.e., bulldozers, backhoes, etc.) and drill rigs.

Historical Considerations

A fairly large percentage of DOD buildings are considered historic structures, and the historic preservation office should be consulted to talk through any potential historic preservation issues. The primary issue with retrofitting historic buildings with GSHP systems will be with interior upgrades of the HVAC distribution system.

System Design

Building Thermal Load

When sizing a GSHP system (or any HVAC system), it is important to complete a thorough estimate of a building's thermal load. There are many examples of over- or under-sized HVAC systems that do not perform as expected because this simple and inexpensive calculation was overlooked in the design process. Good building thermal load estimates are the foundation of a successful HVAC system that will save energy and money. The key parameters for determining thermal loads in new construction are building type (construction), usage, and local climate. For existing facilities, the nameplate capacity of the existing heating and cooling system should be collected and used to size the system. If the heating system capacity is greater than the cooling system capacity, then the system should be sized to meet the peak heating load as a first step. If a facility has a heating plant rated at 1,800 MBH and a 100-t chiller, then the system would be sized at 1,800 MBH / 12 t/MBH = 150 t, unless part of the heating load was going to be met with an onsite boiler as a hybrid system. The actual operational heating and cooling output should also be reviewed to make sure the existing heating and cooling system is correctly sized. For larger commercial buildings, a building automation system (BAS) should be utilized to determine the hourly cooling and heating energy output and calculate the annual heating and cooling energy usage. If BAS data are not available, then temporary sub-metering should be installed to monitor heating and cooling system energy use. These data can be used to ensure the system is properly sized and the assumptions for daily energy usage profiles are calculated correctly.

Loop Field Sizing

The size of the loop field is a function of building thermal load and subsurface thermal parameters. These coupled with land availability and site specific regulations inform the decision about loop field type and configuration. For horizontal HEs, it is recommended that soil samples be collected at the proposed installation depth interval for analysis to determine relevant thermal parameters. If a vertical HE is being considered, a test borehole should be drilled to an adequate depth and a thermal response test completed to determine the in situ values of thermal parameters. These tests are important and should be a requirement for any closed-loop vertical HE. For surface water HEs, information about temperature at depth, average depth, and current/tidal/water level fluctuations should be collected and incorporated into the design process.

Horizontal Loop Fields

Horizontal HEs will require the largest amount of land disturbance to be installed (see Table 28), but typically do not require special permitting due to their shallow installation depth (<10 feet). Installation and local building rules should be reviewed and buried utilities identified prior to excavation. Because loop fields have long warranties (as discussed below), these types of systems can be installed under parking lots or grassy areas. Coordinating with other infrastructure construction projects can be beneficial.

Table 28. Example of the Land Area Disturbance Required to Service One Ton of Heating/Cooling for Various Loop Fields

Loop Type	Surface Area (ft^2) per Ton
Horizontal	1,500–2,000[a]
Slinky	1,200–1,600[a]
Vertical	300–600[b]

[a] assumes installed 6 feet below ground surface

[b] area required for drill rig and supporting equipment

Vertical Loop Fields

Due to space constraints in developed areas, vertical systems are a suitable alternative to horizontal systems. Borehole depth and diameter are dependent upon subsurface thermal parameters and whether the loop will be open or closed. Buried utilities should be identified prior to drilling.

Open Versus Closed Loop

An important constraint on the ability to utilize an open-loop system is local, state, and/or federal regulations, especially in areas where water resources are scarce or protected and in areas where contamination may be present. Open-loop HEs will require more planning and permitting activities compared to closed-loop HEs, which require minimal permitting. An important caveat is in areas where contamination may be present, special drilling techniques may be necessary to prevent migration of contaminants for both open- and closed-loop systems.

Open-loop vertical HEs require wells that are typically deeper and larger in diameter than closed-loop vertical systems; however, fewer wells are required to service loads, because water is a better heat exchange medium than soil/rock. For example, an open-loop well can service 10+ tons of thermal load while a closed-loop well typically does not exceed 4 tons per borehole (typical is 2 tons). The drawback to open-loop vertical HEs is that they typically require more planning and permitting due to potential impacts on water resources, and in some instances are not allowed if local groundwater is scarce, protected, and/or contaminated. Because of these regulatory issues, closed-loop vertical HEs are typically used. In fact, these types of systems are becoming the most common form of loop installation due to the ease of permitting and minimal land disturbance during construction.

Surface Water

The primary consideration for placement of a surface-water HE is the depth at which the loop (or inlet/outlet) is installed to avoid seasonal water level fluctuations, diurnal and seasonal tidal variation, and/or watercraft traffic. Surface-water installations also need to be installed at a depth below where the water column temperature is relatively stable; this varies by water body type and local climate. The rule of thumb for surface-water installations is that the average installation depth should be below at least 6 feet of water. The area required for installation of a closed-loop surface-water HE is between 50 ft^2 and 250 ft^2 per ton, regardless of whether a metal-plate or coiled HDPE HE is installed. This is much less area than is required for horizontal slinky systems for two reasons: 1) instead of spreading the slinky out in a trench, it is compressed/stacked in columns; and 2) significantly less piping/material is needed because water can dissipate heat much more efficiently than soil/rock. These types of systems can be difficult to permit for rivers, oceans, and lakes due to ownership issues and habitat protection. However, if a pond is available within the boundaries of an Army installation and it is large and deep enough, it is worth considering.

Metering

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the MDMS. Monitoring systems do not come standard with most GSHP installations and should be specified in the contract to ensure proper operation and energy production in out-years. At a minimum, pressure and temperature metering of the loop field should be required to ensure it is working properly. The cost of installing a monitoring system is nominal (<$1,000), and in cases where the facility has a BAS, it should be tied into the existing BAS.

Controls

Based on industry data, the primary reason a GSHP system may not work as expected is due to system controls. GSHP systems require different set points than conventional HVAC systems because they operate at relatively lower heating and higher cooling temperatures, which requires the system to be run on a continuous, variable delivery basis (i.e., instead of turning on and off as set points are reached the system ramps up and down to provide the necessary space conditioning). Despite the continuous operation, a properly designed and installed GSHP system will save money and provide improved space comfort. It is imperative that the GSHP system designer and installer be properly accredited with a proven record of successful installations.

Estimating Savings

Equipment Lifetime

Heat pumps are warrantied for 20–25 years, and their lifetime should be assumed to be 25 years. Loop fields that are closed (i.e., utilize HDPE piping) are typically warrantied for 50 years, while open-loop concepts typically have warranties similar to the heat pumps (i.e., 20–25 years). When completing a life-cycle assessment, energy managers can either model the system on a 25- or 50-year cycle for the ECIP application.

Policies and Permits

GSHP system installation requires permits. Standard building HVAC and electrical permits are required for the heat pumps and HVAC distribution systems. The type and complexity of permitting required for the loop field installation depends on the type (i.e., open or closed) and configuration, as well as local and state regulations. Local GSHP installers are usually the best source of information for determining permitting requirements.

GSHP systems are eligible for federal and sometimes state income tax credits, and in some cases utility incentives. The Database of State Incentives for Renewables and Efficiency[39] is a good source of information on federal, state, and utility incentives for GSHP systems.

Estimating GSHP System Capital Costs and O&M Costs

Capital Costs

Capital costs for GSHP system installations are dependent on whether the installation is new or retrofit and the type of loop field employed. There are also economies of scale with GSHP installations, with larger installations having lower capital costs on a per-ton basis.

For new construction, closed-loop GSHP system capital costs can range from $5,000–$10,000/t (average $7,500/t for the entire system). For a retrofit, the range is $7,000–$17,000/t (average $12,000/t). Most of the increased cost is associated with demolition and retrofit of the old HVAC system.

Open-loop systems are typically less expensive compared to closed-loop systems, and range from $3,000–$6,000/t. The lower cost for open-loop systems is due to a lack of HDPE piping and the reduced number of wells or lack of excavation. However, project management and permitting costs can be significantly higher for these types of loop systems. Closed-loop systems require less permitting (in general) and are typically easier to design if good subsurface thermal parameter information is available. Typical installed costs for new construction for the various closed-loop configurations are summarized in Table 29 (excluding heat pump costs, loop field only). Costs are differentiated by mature and immature markets. A mature market is one in which there are more than eight qualified designers, installers, and drillers in a given region. Geoexchange.org is a good resource for determining the number of installers in a given region. Examples of mature regions include: southern California, Oklahoma, Illinois, and Iowa; immature examples include Colorado, New Mexico, Missouri, and Indiana.

[39] Database of State Incentives for Renewables and Efficiency (DSIRE). Accessed March 2015: http://www.dsireusa.org/.

Table 29. Installed Cost for Various Closed-Loop Configurations in New Construction

Configuration	Mature Market ($/t)	Immature Market ($/t)
Surface Water	2,500	5,000
Horizontal	3,500	7,500
Slinky	3,000	7,000
Vertical	4,000	8,000

Source: Goetzler et al. 2009, Rafferty 2008, EIA 2007[40]

Heat pump costs range from $2,500–$5,500/t depending on the size, fan type, and local market. Another factor is whether the heat pump is designed to provide DHW or not. Installation costs (including ductwork) make up the remainder of the capital costs for GSHP systems. In terms of exterior loop field vs. interior mechanical system costs, typical new construction ratios range from 50%/50% to 35%/65%, and retrofits range from 45%/55% to 25%/75%.

O&M Costs

GSHP systems come with equipment warranties (as described above); however, they do not necessarily come with a performance warranty. This is one reason it is critical to find a certified designer and installer with a history of successful projects. With that said, if the system is installed properly, GSHP systems have very low O&M costs compared to conventional heating and cooling systems, in part due to lack of combustion. GSHPs have only one moving part, which is the turbine on the circulation pump located inside the building. The loop field is buried and comes with a 50-year (closed loop) or 25-year (open loop) warranty. Loop fields rarely, if ever, need to be replaced, so installations can be placed under parking lots, sports fields, or open space. The pavement or sod on the surface will typically be replaced multiple times before the loop field is replaced. For economic analysis, an annual O&M cost of $6-$8 per ton installed is typically used for GSHP systems, which is about one-third that of conventional HVAC systems.

Estimating Energy Production

Energy use can be estimated with the following free software tool:

RETScreen: http://www.retscreen.net

Other good sources of information on GSHP systems include:

- International Ground Source Heat Pump Association (IGSHPA): http://www.igshpa.okstate.edu/

[40] Market values compiled by Michael Hillesheim at NREL from the following sources:

Goetzler, W., Zogg, R., Lisle, H., Burgos, J. (2009). *Ground-Source Heat Pumps: Overview of Market Status, Barriers to Adoption, and Options for Overcoming Barriers*. U.S. Department of Energy: EERE - Geothermal Technologies Program. Prepared by Navigant Consulting. Accessed March 2015: https://www1.eere.energy.gov/geothermal/pdfs/gshp_overview.pdf.

Rafferty, Kevin. (2008). "An Information Survival Kit For The Prospective Geothermal Heat Pump Owner." Accessed March 2015: https://www.heatspring.com/free_tools/geothermal-survival-kit/download.

EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case, 2nd Edition. (2007). Energy Information Administration. Prepared by Navigant Consulting. Accessed March 2015: http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

- Geoexchange: http://www.geoexchange.org/.

Example Calculation

A two-story, 100,000-ft^2 office building located in Colorado Springs, Colorado, is interested in retrofitting the existing HVAC system with a GSHP. The existing heating and cooling system is at the end of its useful life, and rather than replacing it, the site is interested in investigating the cost effectiveness of installing a GSHP system as an alternative to conventional HVAC systems. The facility passed the project development considerations listed above, and based on land availability and local permitting and regulations, a closed-loop vertical HE was determined to be the best option (Table 30).

Table 30. System Sizing, COP, and Cost Information

Parameter	GSHP System	Conventional System
Size (t)	200	200-t boiler / 125-t chiller
COP – Heating	4	0.6
COP – Cooling	5	2.8
Installed Cost ($)	1,400,000	950,000[a]
Incremental Cost of GSHP System ($)	450,000	
O&M ($/yr)	1,400	7,000
O&M Savings of GSHP System ($/yr)	5,600	

[a] Assumes that both the existing cooling system and heating system would need to be replaced for a total replacement cost of $950,000

The following information was input into RETScreen version 4.

On the Start tab:

- Project Type: Combined Heating & Cooling
- Analysis Type: Method 1

  Method 1 includes simpler financial analysis and should be selected for ECIP projects, as a separate financial analysis is conducted in the ECIP form.

- Heating Value Reference: Higher Heating Value
- Climate Data: Colorado Springs.

Click "show settings" and change *Unit* values from metric to imperial.

On the Load and Network tab:

Heating Project

- Base Case Heating System Single Building – Space Heating

- Heated Floor Area 100,000 ft^2
- Fuel Type Natural Gas (MMBtu)
- Seasonal Heating Efficiency 70% *(efficiency of old existing boiler)*
- Heating Load for Building 24.0 Btu/h/ft^2 *(based on size of existing heating system)*
- Domestic Hot Water 0%
- Fuel Consumption Annual 6,617 MMBtu
- Fuel Rate $6.00/MMBtu
- Energy Efficiency Measures 00%.

Cooling Project

- Base Case Heating System Single Building – Space Cooling
- Heated Floor Area 100,000 ft^2
- Fuel Type Electricity
- Coefficient of Performance 2.8
- Cooling Load for Building 16 Btu/h/ft^2 *(based on size of existing cooling system)*
- Non-Weather Dependent Cooling 0%
- Fuel Consumption Annual 249 MWh
- Fuel Rate $0.0.058/kWh
- Energy Efficiency Measures 0%.

On the Energy Model tab:

Proposed Case Cooling System

- Technology Heat Pump
- Fuel Type Electricity
- Fuel Rate $58.00/MWh
- Capacity 200 RT (rated tons)
- Coefficient of Performance 4.0A.

Peak system is not required because the GSHP system was sized to meet the peak heating and cooling load; however, values for Capacity and COP (same as listed above) must be entered. Manufacturer and Model are not required.

Proposed Case Heating System

- System Selection — Baseload System
- Technology — Heat Pump
- Fuel Selection Method — Single Fuel
- Fuel Type — Electricity
- Fuel Rate — $58.00/MWh
- Capacity — 2.4 MMBtu/h
- Seasonal Efficiency — 400% *(equates to a COP of 4).*

A peak system is not required.

Proposed Case System Characteristics

- Technology — Not required.

Proposed Case Summary

- Heating Fuel Consumption: — 339 MWh
- Cooling Fuel Consumption: — 175 MWh.

Initial Cost

- Other: — $1,400,000
- Incremental Installed Cost — $450,000 (see Table 30).

Annual Costs and Debt Payments

- O&M Costs: — $5,600/yr.

The results of the retrofit-scenario analysis indicate that the simple payback is around 15 years for this example. It should be noted that this system would not be cost effective if the existing chilled water plant and heating plant did not need to be replaced. Even with the chiller and boiler replacement costs included, the GSHP installed costs had to be on the lower end of the typical installed cost range for retrofits. This site also has very cheap electricity rates, which benefit GSHP. Other sites with higher electricity rates or lower natural gas rates would have a more challenging time finding a project that is cost effective in a retrofit, as the expensive electricity costs would negate any potential heating cost savings and hurt the project economics.

Table 31 outlines the ECIP form economic parameters for the GSHP system in this example.

Table 31. GSHP Example, Economic Parameters

Parameter	Value	Notes
Installed Cost	$7,000/t	200 t x $7,000/t = $1,400,000 total
Replacement Cost Savings	$950,000	Cost to replace old heating and cooling system
Incremental Installed Cost	450,000	$1,400,000 - $950,000 (to replace old heating and cooling system) = $450,0000
O&M Cost	($5,600)	
Analysis Period	25 years	
Energy Savings	5,713 MMBtu/yr	-904 MMBtu/yr from electricity plus 6,617 MMBtu/yr from natural gas for a net savings of 5,713 MMBtu/yr. This is the overall energy savings from installing a GSHP; the electricity use goes up because the natural gas heating load is transferred to an electrical load, but the overall energy use goes down by 5,713 MMBtu/yr.
Electric Rate	$0.058/kWh	

The investment costs as outlined in the ECIP form are shown in Table 32 below.

Table 32. GSHP Example, Investment Costs

Parameter	Value	Notes
Construction Cost	$450,000	
SIOH (5.7%):	$25,650	Calculated automatically in ECIP worksheet
Design Cost (4%)	$18,000	Calculated automatically in ECIP worksheet. However, most of the quoted prices for RE already include design costs, so energy managers should consider removing the additional 4% design cost for their project or reducing the construction cost estimate by 4% so that design costs are not counted twice.
Salvage Value of Existing Equipment	$0	
Public Utility Company Rebate	$0	
Total Investment	$493,650	Calculated automatically in ECIP worksheet

Energy savings are input into the ECIP form as shown in Table 33 below.

Table 33. GSHP Example, Energy Savings in ECIP Form

Parameter	Value	Notes
Electric Cost	$17/MMBtu	$0.058/kWh /3,412 Btu/kWh x 1,000,000 MMBtu/Btu = $17/MMBtu
Electric Savings	($904)	
Electric Cost Savings	($15,371)	
Electricity Discount Factor	17.57	Based on 25-year discount factor for electricity for Colorado
Discounted Electricity Savings	($270,070)	
Natural Gas Cost	$6/MMBtu	
Natural Gas Cost Savings	$39,702	Calculated automatically in ECIP worksheet
Natural Gas Discount Factor	22.63	Based on 25-year discount factor for natural gas for Colorado
Discounted Natural Gas Savings	$898,456	Calculated automatically in ECIP worksheet
Total Discounted Savings	$628,387	Calculated automatically in ECIP worksheet

O&M savings are input into the ECIP form as recurring non-energy savings as shown in Table 34 below.

Table 34. GSHP O&M Savings in ECIP Form

Parameter	Value	Notes
Annual Recurring	($5,600)	
Discount Factor	17.41	Based on discount factor for finding the present value of annually recurring uniform costs (non-fuel)
Discounted Cost	$97,496	Calculated automatically in ECIP worksheet

The system economics are summarized in the ECIP form as shown in Table 35 below.

Table 35. GSHP Example, Summary in ECIP Form

Parameter	Value	Notes
First-Year Dollar Savings	$29,931	Calculated automatically in ECIP worksheet
Simple Payback	16.5	Calculated automatically in ECIP worksheet
Total Net Disc. Savings	$725,883	Calculated automatically in ECIP worksheet
SIR	1.47	Calculated automatically in ECIP worksheet

For this example, the SIR is greater than 1, and the project would also need to score well in all of the non-energy savings/economics categories to be approved for funding.

Training

Several webinars, educational materials, and guidebooks are available for GSHP.

- Heat Spring is a good resource for basic webinars and trainings on GSHP. Most trainings have a fee: https://www.heatspring.com/categories/geothermal-training-courses
- The International Ground Source Heat Pump Association (IGSHPA) and GeoExchange provide information and educational materials on their websites:
  http://www.igshpa.okstate.edu
  http://www.geoexchange.org
- The European Renewable Energy Council (EREC) provides an online guidebook on GSHP:
  Ground Source Heat Pump: A Guide Book:
  http://www.erec.org/fileadmin/erec_docs/Projcet_Documents/RESTMAC/GSHP_brochure_v_2008.pdf.

Army Bases That Have Successfully Installed GSHP Systems Funded by ECIP

Ft. Knox, Ft. Polk, Sierra Army Depot, and Ft. Bragg are just some of the Army installations that have successfully installed GSHP systems (Table 36).

Table 36. GSHP System, Base Contacts

Name	Installation	Title	Phone	Email
R.J. Dyrdek	Ft. Knox	Energy Manager	502-624-2604	robert.d.dyrdek.civ@mail.mil
Coby Jones	Ft. Bragg	Energy Manager	(910) 432-6010	joseph.c.jones4.ctr@mail.mil

BIOMASS HEATING

Technology Description

Biomass can be used to generate heat and/or electricity. This guide focuses on biomass heating projects, as most biomass power or biomass combined heat and power (CHP) applications would require funding that exceeds typical ECIP funding levels. Larger biomass power or CHP applications should be pursued through power purchase agreements. Biomass projects are much more complex than solar projects, and an experienced biomass consultant should be included in any biomass feasibility studies.

Several technologies are available to convert biomass feedstocks into heat and electricity, including combustion, pyrolysis, gasification, and anaerobic digestion. This guide focuses on combustion, which is the direct burning of a feedstock such as wood waste with air to produce hot water or steam. This is typically the most economical method of converting biomass fuel to heat.

Biomass heating systems can be as simple as a wood stove, pellet stove, or fireplace radiating heat into the surrounding space. More complicated systems provide steam or hot water to meet space heating and water heating requirements. Figure 17 illustrates a biomass heating system in which biomass energy is converted into steam and sent to a nearby building that utilizes the heat in the steam for space heating and water heating.

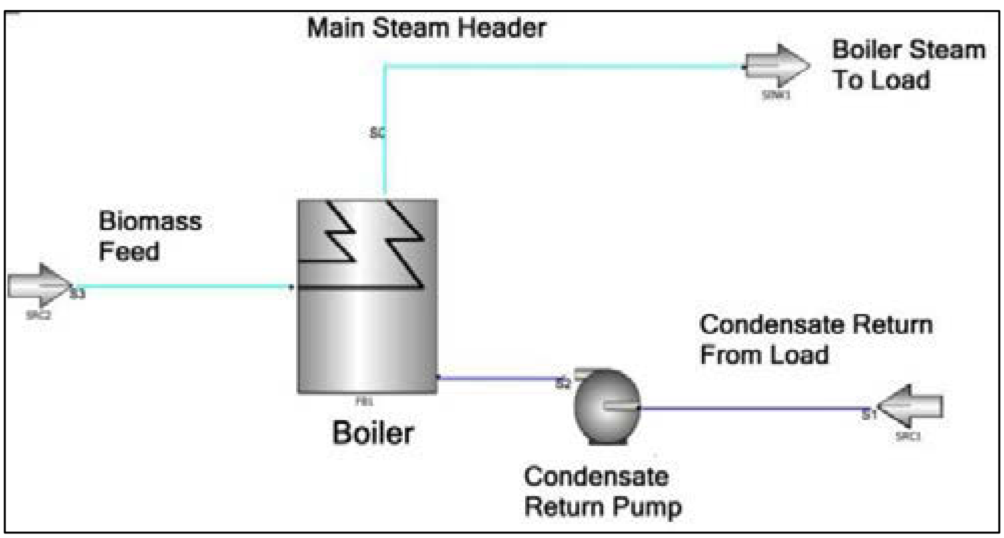

Figure 17. Thermal-only biomass energy system
Image created with GE GateCycle software by Gregg Tomberlin, NREL

In a heating system using steam as the working fluid, the steam is condensed as the heat is extracted; the warm condensate is then pumped back to the biomass facility where it is reintroduced to the boiler and converted to steam. Biomass systems using hot water for the working fluid are similar, except that there are no phase changes—the water is in liquid form throughout the heating cycle.

A typical biomass heating system has the following major components: fuel receiving, storage, and handling; combustion system (and steam generator where applicable); and air pollution control equipment. Each of these components is described in more detail below. Other equipment and auxiliaries include: stack and monitoring equipment; instrumentation and controls; ash handling; fans and blowers; water treatment; electrical equipment; pumps and piping; and buildings.

Fuel Receiving, Storage, and Handling

Biomass can be received at the site by truck, rail, or barge. It can be delivered as chips, pellets, or logs; logs can be processed onsite into chips. Wood chips are typically stored in a fuel yard (exposed or covered) or in storage silos. Figure 18 shows a large silo, but smaller models are available. Wood pellets are stored in silos and are easily handled and fed with standard equipment.

Figure 18. Biomass storage options: (left) a fuel yard and (right) a fuel silo

Photos by (left) Warren Gretz, NREL 04736 and (right) Gerry Harrow, NREL 15041

Fuel handling can be fully automated or semi-automated; a semi-automated system will have lower capital costs, but will require additional labor. A fully automated system will typically be installed below grade, with wood chips delivered by truck to the storage bin; conveyor belts automatically feed chips from the storage bin to the boiler. Semi-automated systems typically include above-ground chip storage and a hopper with capacity to supply the boiler for a few days. An operator moves woody biomass from the storage area to the hopper as needed. Operator workload is estimated at 60–90 minutes per day.[41]

Combustion System and Steam Generator

The most common system for converting solid biomass fuel into energy is a direct-fired combustion system. The fuel is typically burned on a grate or in a fluidized bed to create hot combustion gases that pass over a series of boiler tubes, transferring heat into water inside the tubes and creating steam. The combination of the burning apparatus and the heat transfer surface areas are typically referred to as the boiler.

Boilers are differentiated by their configuration, size, and the quality of the steam or hot water produced. Boiler size is most often measured by the fuel input in millions of Btu per hour (MMBtu/h), but it may also be measured by output in pounds

[41] *Woodchip Heating Fuel Specifications in the Northeastern United States*. (2011). Biomass Energy Resource Center. Accessed January 8, 2013: http://www.biomasscenter.org/resources/publications.html.

per hour of steam produced. The two most commonly used types of boilers for biomass firing are stoker boilers and fluidized bed boilers. Either of these combustion systems can be fueled entirely by biomass fuel or co-fired with a combination of biomass and coal or other solid fuel.[42]

The traveling grate stoker boiler introduces fuel at one end of the furnace. The grate slowly moves the fuel through the hot zone until combustion is complete and the ash falls off at the opposite end. The fuel is either dropped onto the grate and travels away from the feeder or is thrown to the opposite end and comes back towards the feeder. The latter is called a spreader stoker. A fluidized bed boiler introduces feedstock into the bed with a heat transfer medium (typically sand).[43] The bed material is fluidized using high-pressure air from underneath the grate, creating a good mixing zone.

Air Pollution Control

Biomass is a relatively clean fuel and contains lower quantities of the pollutants commonly found in coal and other solid fuels. The primary pollutants of concern in biomass combustion are CO, NOx, and particulate matter (PM).

CO emissions are largely a function of good combustion. Good air mixing will oxidize most CO molecules into carbon dioxide (CO_2), which is not a regulated pollutant. The control of NOx is not always required, but NOx can be controlled by either selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR). SNCR is accomplished by the introduction of nitrogenous reagents (urea or ammonia) at specific temperatures, creating a reducing reaction. SCR is a similar process but also uses a catalyst to achieve higher removal efficiencies.

For PM, the small ash particles are captured in the fabric of large bags, and the bags are pulsed occasionally to dislodge the dust into an ash hopper for removal. These systems are known as fabric filters or baghouses. Electrostatic precipitators (ESPs) are also commonly used for particulate removal.

EPA's "Final Air Toxics Standards for Industrial, Commercial, and Institutional Boilers at Area Source Facilities" was released on February 1, 2013. The following provisions apply to new biomass boilers:[44]

- New boilers with heat input capacity greater than 10 MMBtu/h that are biomass-fired or oil-fired must meet Generally Achievable Control Technology (GACT)-based numerical emission limits for PM.
- New biomass-fired boilers with heat input capacity of 30 MMBtu/h or greater must have filterable PM of fewer than 3.0E–02 lb/MMBtu of heat input.
- New biomass-fired boilers with heat input capacity of between 10 and 30 MMBtu/h must have filterable PM of less than 7.0E–02 lb/MMBtu of heat input.
- New biomass-fired boilers with heat input capacity of fewer than 10 MMBtu/h must minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If

[42] *Biomass Combined Heat and Power Catalog of Technologies*. (September 2007). U.S. Environmental Protection Agency, Combined Heat and Power Partnership. Accessed January 8, 2013: http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf.

[43] Crawford, M. "Fluidized Bed Combustors for Biomass Boilers." (September 2012). ASME. Accessed January 10, 2013: https://www.asme.org/kb/news---articles/articles/boilers/fluidized-bed-combustors-for-biomass-boilers.

[44] "National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers." (2013). U.S. Environmental Protection Agency. 78 FR 7488. Accessed January 2013: http://www.epa.gov/airtoxics/boiler/boilerpg.html.

manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. [45]

Project Development Considerations

Key project development considerations for siting, system design, estimating savings, and policies and permits are presented in this section.

Siting

Centralized Versus Distributed Heating Systems

Many DOD installations have existing district heating systems where a central unit (commonly a natural gas or oil-fired boiler) provides heat to nearby buildings through a series of pipes carrying hot water or steam. Capital costs are high for new district heating systems due to the network of piping and heat exchangers and other equipment that must be installed for each customer. District heating systems are most cost effective where multiple heating loads are located in close proximity and lengthy piping systems are not required. These centralized district heating systems (both hot water and steam) are typically ideal candidates for biomass heating systems, as the biomass boilers can provide baseload heating to the facilities on the district loop. Smaller biomass boiler systems can also be applied to individual facilities on a base and need to be evaluated on a case-by-case basis.

Space Requirements

Biomass heating systems are significantly larger than fossil fuel systems of the same heating capacity. Fuel receiving, storage, and handling equipment requires additional space, and often requires modifications to an existing boiler building.

Fuel Delivery and Truck Traffic

Due to the low energy density of biomass fuel, truck traffic will generally increase, compared to propane or fuel oil. In addition, a truck route to the fuel storage area must be designed for the appropriate delivery vehicles—such as large chip vans. For larger plants, truck dumpers are common. Biomass delivery trucks can typically hold approximately 20 tons of biomass per truck. At an energy content of 5,500 Btu per green pound, 20 tons of wood chips have an energy content of about 220 MMBtu. Energy and installation security issues surrounding biomass delivery trucks need to be taken into consideration and addressed when evaluating the feasibility of a biomass heating system.

System Design

Biomass System Sizing

The output of a well-designed and constructed biomass thermal system (again, assuming adequate quantities and qualities of feedstock are always available) is strongly correlated with the daily, monthly, and annual heating loads—subject to size constraints. A biomass boiler has a limited turndown ratio—meaning that it can't be operated below a set percentage of its rated output. If the turndown ratio is specified as 4-to-1, then it can only be operated between 25% and 100% of its rating (e.g., a 1-million Btu/h boiler with a turndown ratio of 4-1 can be operated between 250,000 and 1,000,000 Btu/h). If the load is lower than this—for example, on a cool fall day—the fossil fuel backup system should be operated instead.[46] Because

[45] Federal Register. Vol. 78, No. 22. Friday, February 1, 2013. Rules and Regulations. p. 7518.

[46] One way around this limitation is to install two smaller boilers instead of one large boiler. This will allow more flexible operation, but will require more space and will incur additional costs for engineering, integration, and equipment. This can potentially allow the biomass system to supply close to 100% of the annual heating load.

of this, biomass heating systems are generally designed with a maximum capacity smaller than the peak load. On the coldest days, the fossil fuel system will need to operate to supplement the biomass boiler. A good rule of thumb is to size the system to meet about 90% of the annual load.

Heating Load System Integration

Integration of the biomass boiler with a new or existing fossil fuel system requires careful engineering and controls design.

Biomass Fuel Sources

Wood used for a biomass energy plant is generally low-valued material, often produced as residue from harvesting of more valuable material like saw logs for dimensional lumber. It can also result from land maintenance and clearing operations, thinning for fire mitigation, urban tree trimming, storm clean-up, power line right-of-way maintenance, and disposal of diseased trees (e.g., beetle kill). Note that this material is generally a waste product or a product of procedures that improve forest health or reduce risks to the forest or to people living near forests. Unlike other RE technologies, biomass projects often compete for resources with other users, which can include pellet production, the oil and gas industry, animal bedding, and other biomass heat and power projects. Some biomass fuel may be available on the installation, but typically some or all of the fuel will need to be sourced offsite.

Some tools are available that can provide data for an initial assessment of biomass availability. One is NREL's Biofuels Atlas (http://maps.nrel.gov/biomass), which is a GIS tool containing data on resources such as crops, crop residues, wood, and methane. It also contains data on existing biopower plants, biofuels facilities, and other power plants.

Figure 19 shows the Biofuels Atlas with data on forest residues and primary mill residues for an area near Seattle, Washington. Different colors represent different production ratios of each feedstock. Production ratios give an indication of biomass produced in a region, but it would also be important to know how much of that material is already allocated to other uses—due to both existing and future projects. The Biofuels Atlas can provide locations of individual biopower plants—and the annual electrical production from those plants—but it doesn't show other competing users (e.g., pellet plants, animal bedding).

The layers in the Atlas can be turned on and off by checking boxes in the "layers" window on the left side of the screen. It is easier to interpret the map with fewer layers displayed.

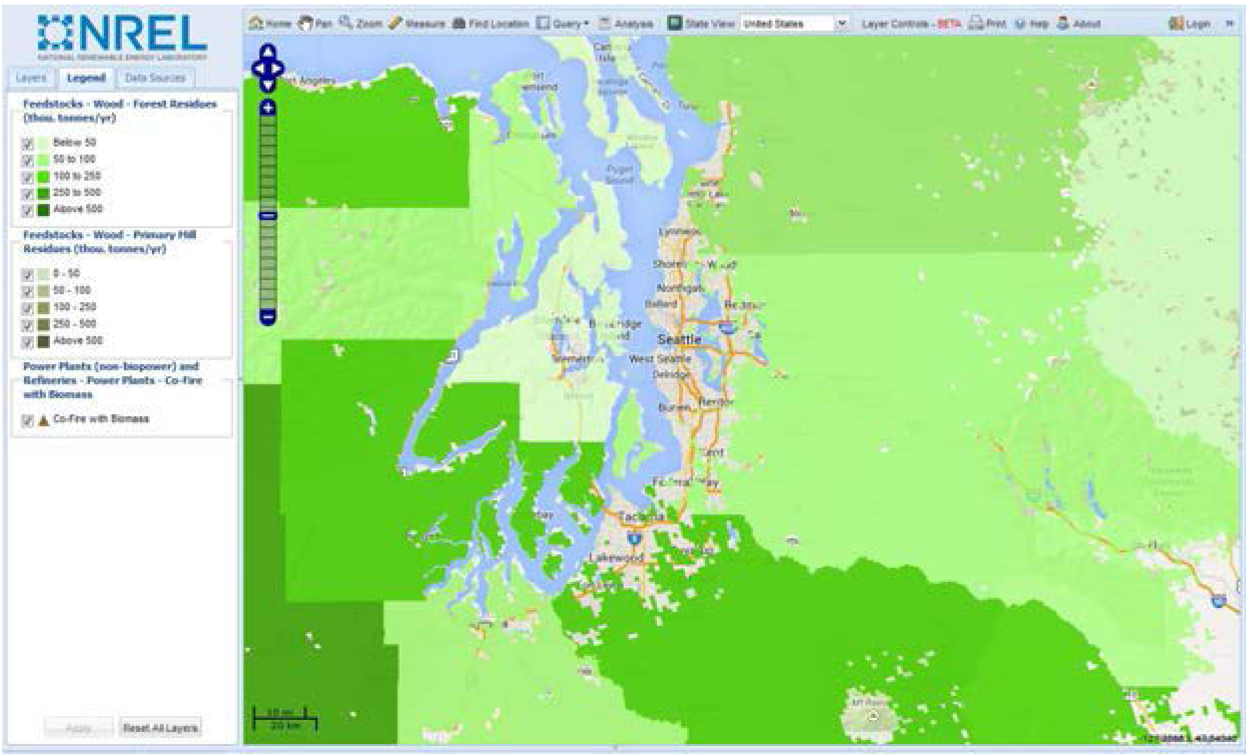

Figure 19. NREL Biofuels Atlas showing forest and primary mill residues near Seattle, Washington

Other tools are available, but they tend to be state- or region-specific. These are often sponsored by state energy offices, or regional U.S. or state forest service offices.

Metering

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the MDMS. Boiler plant metering systems typically consist of metering supply water temperature, return water temperature, and flow rate in order to calculate thermal energy production. Additional information on firing rate, combustion air properties, etc. are typically monitored by the internal boiler controls and can be tied into the onsite BAS.

Biomass Fuel Properties

The operating success of a biomass heating project is highly dependent on properties of the biomass feedstock; the most significant of these properties include energy content, moisture content, and ash content. Fuel handling and processing procedures determine wood cleanliness and chip size, which can significantly affect system reliability and maintenance.

As collected, wood moisture content (MC)[47] typically ranges from 40% in summer and fall to 50% in winter. Moisture content affects the efficiency of a biomass combustion process in a non-linear manner. For example, biomass might contain 4,000 Btu per pound of recoverable energy at 40% MC, and with 50% MC the recoverable energy may only be 3,133 Btu per

[47] In this report, moisture content is specified on a wet basis (wb) [i.e., MC, wb = weight of water ÷ (weight of water + weight of dry wood)]. In some industries, moisture content is reported on a dry basis (db) (i.e., MC, db = weight of water ÷ weight of dry wood). Note that 50% MC, wb = 100% MC, db.

pound. This represents a loss of more than 21% of the energy value. If prices are not adjusted based on feedstock moisture content, the cost per Btu greatly increases with increasing moisture content.

The Southeast Clean Energy Application Center's Wood Energy Calculator can be used to explore the effect of moisture content on energy production.[48] See Figure 20 for an example of the program's inputs and outputs.

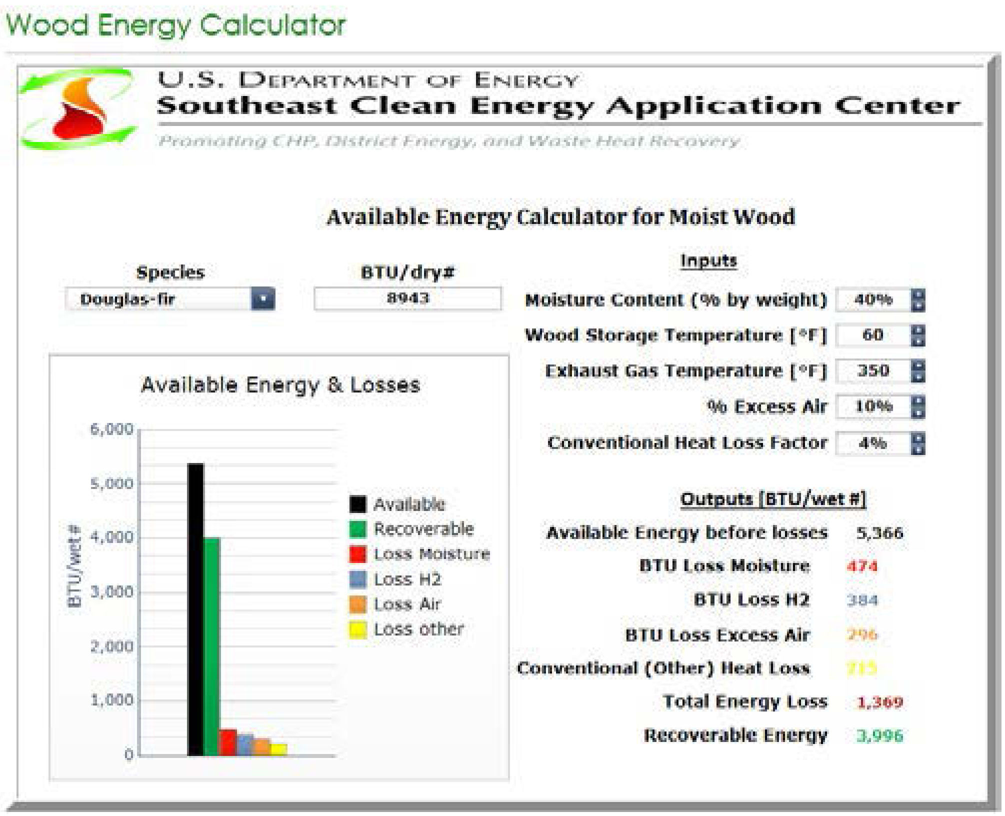

Figure 20. Southeast Clean Energy Application Center's wood energy calculator

Image from DOE

Estimating Savings

Maintenance

Biomass systems are reliable, but typically require more maintenance—both scheduled and unscheduled—than a system fueled with natural gas or oil. To reduce the possibility of loss of heating for a facility or installation, it is common to include a backup or supplemental fossil-fueled boiler. Using clean, high-quality feedstocks will significantly reduce both planned and unplanned maintenance, and improve system operation, but usually at a higher cost than lower-quality fuels.

Electric Energy and Demand Increase

Biomass heating systems, due to the motors for running conveyance equipment and fans, can increase electric power consumption and peak demand compared to a fossil fuel system.

[48] Southeast Clean Energy Application Center. "Wood Energy Calculator." Accessed June 19, 2013.

Equipment Lifetime

Biomass systems can operate for 40 years or more with proper maintenance. For the purposes of financial calculations, a 20- or 25-year life is usually assumed.

Policies and Permits

The size and design of the plant, the method of steam generation, and local permitting requirements ultimately affect the permits required for a biomass heating plant. State agencies generally handle permitting. State and local codes and regulations will need to be reviewed for each project. Federal regulations and permits potentially required for a biomass heating project are briefly summarized below.

- The National Emission Standards for Hazardous Air Pollutants cover boilers.[49]
- EPA's National Ambient Air Quality Standards say combustion devices must emit below stated levels.[50]
- 2011 EPA Clean Air Act pollution standards require biomass boilers over 10 million Btu/h for 876 or more hours per year to meet numeric emission standards.[51]
- 40 CFR Part 60 limits emissions on steam generating units over 10 million Btu/h.
- The National Pollutant Discharge Elimination System covers what happens to wastewater from the facility. This will typically not apply to a biomass heating system, but should be included in an environmental review.[52]
- Prevention of Significant Deterioration and construction permits require any new major source of pollutants to conduct analysis and use best control technologies.[53]
- The Risk Management Plan Rule requires new facilities to develop a plan if certain chemicals are stored.[54]

Estimating Biomass Heating Capital Costs and O&M Costs

Biomass heating systems tend to have higher capital costs compared to fossil fuel systems; biomass systems' economic advantage tends to derive from their lower fuel costs. Therefore, the economic feasibility of a biomass heating system is primarily dependent on the annual heating loads, the cost of local biomass, and the competing fossil fuel costs.

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[49] "National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers." (2013). U.S. Environmental Protection Agency. 78 FR 7488. Accessed June 19, 2013: http://www.epa.gov/airtoxics/boiler/boilerpg.html.

[50] "National Ambient Air Quality Standards." U.S. Environmental Protection Agency. Accessed June 19, 2013: http://www.epa.gov/air/criteria.html.

[51] "Final Air Toxics Standards for Industrial, Commercial, and Institutional Boilers at Area Source Facilities." U.S. Environmental Protection Agency. 2011. Accessed March 12, 2015: http://www.epa.gov/oaqps001/combustion/docs/20110221aboilersfs.pdf.

[52] "National Pollutant Discharge Elimination System Compliance Monitoring." U.S. Environmental Protection Agency. Accessed June 19, 2013: http://www2.epa.gov/compliance/clean-water-act-national-pollutant-discharge-elimination-system-compliance-monitoring.

[53] "Prevention of Significant Deterioration (PSD) Basic Information." U.S. Environmental Protection Agency. Accessed June 19, 2013: http://www.epa.gov/NSR/psd.html.

[54] "Risk Management Plan (RMP) Rule." U.S. Environmental Protection Agency. Accessed June 19, 2013: http://www2.epa.gov/rmp.

Capital Costs

Because of the many different possible equipment types and different biomass fuels, it is very difficult to provide estimated capital costs for biomass heating installations, but general guidance is provided based on limited published data to enable rough cost estimates for a biomass system. Rough estimates of capital costs for the primary biomass heating equipment—the biomass burner and boiler, fuel storage and handling, pumps, controls, emission control systems, ash handling systems, fire safety systems, and installation—can be derived from Figure 21.

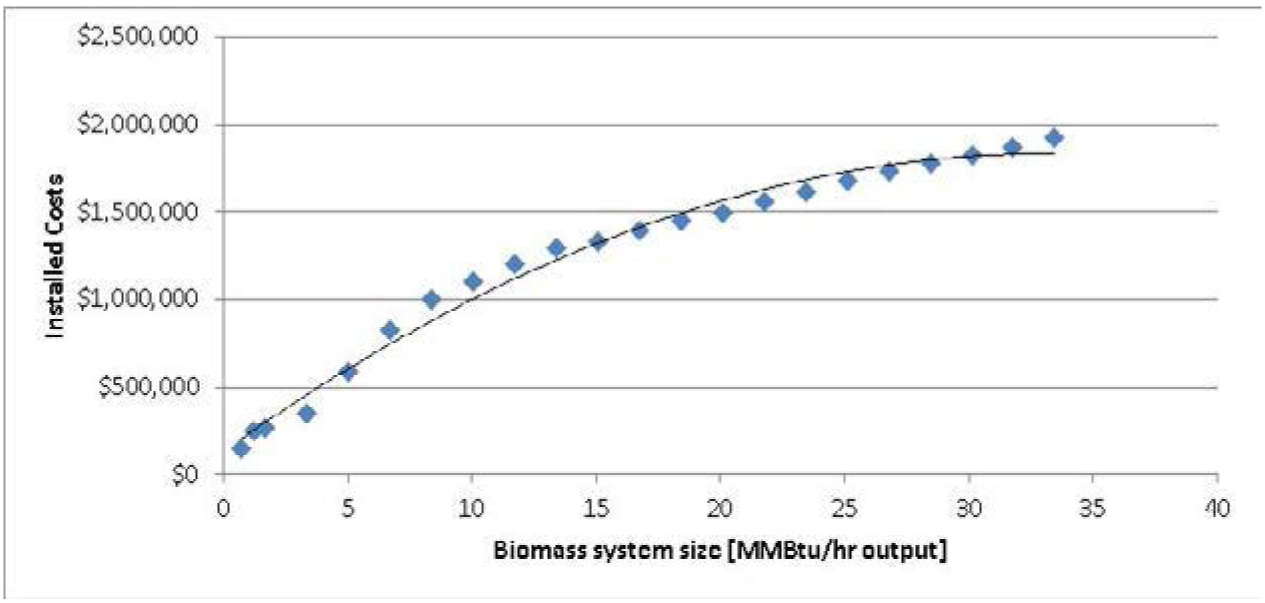

Figure 21. Rough biomass heating system equipment costs (excluding fuel processing and handling equipment) as a function of system output capacity[55]

Costs for piping, excavation, and building modifications are highly variable and site dependent. Additional costs will be incurred for design, engineering, and shipping. As a fraction of hardware costs, these costs might add 20% for a large system to 30% (or more) for a small system.

O&M Costs

Non-fuel O&M costs can be divided into two factors: one due to increases in daily labor requirements, and one proportional to energy production.

A pellet system might require a few hours of maintenance per month, while a chip system—with its more complex fuel handling systems and greater potential variation in fuel quality—might require anywhere from a few hours per week to an hour per day of additional maintenance. This maintenance includes ordering fuel and moving fuel around onsite, with manual and semi-automated systems requiring greater labor. Variable costs are a function of wear-and-tear and include maintenance, ash disposal, and consumables. Fixed O&M costs for a small system tend to be at the high end of the scale, as items like labor grow smaller per unit of energy as systems get larger. In RETScreen, annual costs are entered in terms of

[55] These costs are based on various sources, including manufacturer quotes, actual installations, and theoretical data from the spreadsheet model "Wood Fueled Boiler Financial Feasibility (BoilerProgram.xls)," created by Robert Govett, College of Natural Resources, and the University of Wisconsin-Stevens Point. All costs have been escalated to 2014. http://www.treesearch.fs.fed.us/pubs/26858.

cost per Btu produced, essentially rolling the fixed and variable costs into one number. For a high-level analysis, the user can assume this cost is between $1.00 and $3.00 per million Btu of heat delivered by the biomass system.

Feedstock Cost

An important factor in assessing the feasibility of a biomass project is the cost of the resource. This can be best determined by contacting potential suppliers within a driving distance of about 50 miles from the intended facility. A typical cost for clean wood chips might be in the range of $30 to $50 per green ton.

Delivery price needs to be added to the cost of the biomass fuel. For example, the North Springfield Biomass report[56] estimates a biomass delivered cost (for North Springfield) as follows:

> INRS projects that the "wood component" of biomass fuel for this location will average $27.00 per green ton in 2011, and increase annually by 3%. In order to get a final delivered price, 2.1 times the price of a gallon of diesel should be added; for example, if diesel averages $4.00/gal in 2011, the average delivered cost for biomass fuel is projected to be $35.40.

Escalation rates for biomass are not provided in the NIST Handbook annual supplements, but can be approximated by the escalation rate for diesel fuel. Diesel fuel is a significant component of the price, as it is used to fuel the delivery trucks, as well as the equipment used to harvest and process the biomass. One estimation method is to calculate the annual biomass cost escalation as 60% of the escalation of diesel fuel.

Estimating Energy Production

Energy production can be estimated with RETScreen, a free software tool available at http://www.retscreen.net. A description of the appropriate RETScreen inputs is provided in the example below.

Example Calculation

In this section, an example calculation for biomass heating at a military installation is provided. The example follows a typical feasibility study process for determining the feasibility of integrating a biomass heating facility into an existing installation, which includes the following major steps:

- Determine heating load, including peak, monthly, and annual loads (this is usually done through an analysis of one or more years of historical heating data).
- Determine available biomass, biomass types, biomass vendors, and biomass cost (for a detailed study, this is best completed by a specialized firm, but for an initial analysis, contacting local wood handlers, mills, and forest service offices should be sufficient).

[56] "Biomass Fuel Availability North Springfield, Vermont." Prepared for: North Springfield Sustainable Energy Project, A Project of Winstanley Enterprises, September 2011. Accessed September 11, 2013: http://psb.vermont.gov/sites/psb/files/orders/2012/2012-2/Exh.%20Pet.%20EWK-2.2.pdf.

- Review the site and boiler building:
    - Confirm that there is space for a biomass boiler and fuel storage.
    - Confirm that there is sufficient room for trucks to deliver and dump biomass, and to get in and out.
    - Determine existing boiler types, size, age, condition, and heat distribution type (e.g., hydronic, forced air).
- Estimate capital costs (this is the most difficult part, but could include contacting system manufacturers and vendors; this should be done as a component of the modeling step).
- Estimate O&M costs.
- Enter these data into a spreadsheet model or specialized software like RETScreen[57] to size the biomass and backup systems, estimate fuel requirements, and perform economic modeling.

This example is based on an actual case study, in which a biomass heating system could replace most of the load currently served by the natural-gas-fueled high-temperature hot water plant. Figure 22 shows the average heating load, by month, for the example installation.

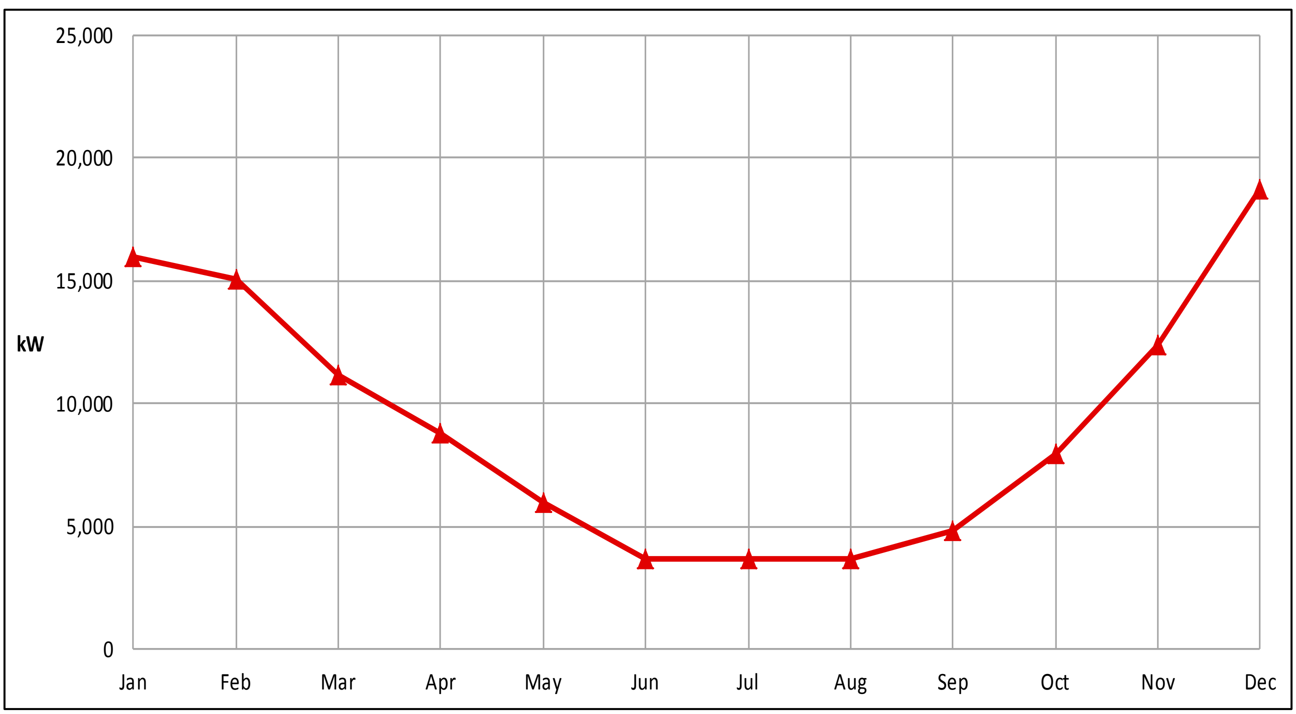

Figure 22. Average heating load, by month, for example system

[57] RETScreen is publicly available at: http://www.retscreen.net/ang/home.php.

The following information was input into RETScreen version 4:

On the Start tab:

- Project Type: Heating
- Technology: Biomass heating
- Analysis Type: Method 2

  Method 2 should be used for biomass heating systems because these are more complex projects.
- Heating Value Reference: Higher Heating Value
- Climate Data: Colorado Springs, Colorado.

On the Load and Network tab:

- Application: Single building – space heating
- Heated Floor Area: 2,914,000 ft^2

  This represents the district heating load made up of multiple buildings. Data on each individual building was not available, so it is modeled as a single building.
- Fuel Type: Natural Gas
- Seasonal Efficiency: 70%
- Heating Load for Building: 29 (Btu/h)/ft^2
- DHW Base Demand: 47%
- Fuel Rate: $5.98/MMBtu
- End Use Energy Efficiency: 0%.

BIOMASS HEATING

On the Energy Model tab:

Baseload heating system and biomass heating system:

- System Selection: Baseload System
- Technology: Biomass
- Fuel Selection Method: Single Fuel
- Fuel Type: Wood waste – mixed softwood
- Fuel Rate: $57.98/ft^2

  We estimated that handling and moving of 10,000 green tons of material sourced onsite would cost the facility about $20 per green ton; quotes of $43/green ton for delivered material were received for the remaining 16,307 green tons required to fuel the proposed system. This results in a weighted cost of $34.26 per green ton, or $57.98 per dry metric ton.[58]

- Biomass Capacity: 45 MMBtu/h

  The system size was varied until the program predicted that 90% of the annual load would be met by biomass; experience has shown that, in general, this percentage provides a good balance between capital costs and operating costs, while nearly maximizing biomass utilization. This resulted in a 45-MMBtu/h biomass heating system, which RETScreen calculated would supply about 255,000 MMBtu/yr to the heating load, offsetting 364,000 MMBtu of natural gas (assuming a 70% efficient natural gas boiler, 255,000/0.7 = 364,000). RETScreen also calculated that approximately 26,300 green tons (at 35% moisture content; 26,300 (1-0.35) / 1.1 = 15,545 dry metric tons) of biomass per year would be required to meet the load. A significant portion of this amount (10,000 green tons) could be procured onsite, with the remaining 16,300 green tons purchased on the local market for this particular example.

- Seasonal Efficiency: 66%

  This is estimated using typical heating system losses, and based on 30%–40% MC feedstock

- Boiler Type: Hot Water.

[58] ((10,000 GT/yr x $20/GT) + (16,307 GT/yr x $43/GT))/(26,307 GT/yr) = $34.26/GT; however, RETScreen cost and use are based on dry metric tons (dmt): $34.26/GT x (1 dry ton/0.65 green ton) x (1.1 dry ton/dry metric ton) = $57.98/dmt.

Peak load heating system ("Peak load heating system" refers to the natural gas-fired back-up/supplemental system):

- Technology: Boiler
- Fuel Type: Natural Gas
- Fuel Rate: $5.98/MMBtu
- Capacity: 40 MMBtu/h

  Note that the biomass system was sized to serve about 90% of annual load, which met 53% of the peak load. Thus, a 40 MMBtu/h natural gas boiler was needed to meet the peak heating loads of the facility.

- Seasonal Efficiency: 70%.

Using $5.98/MMBtu as the natural gas cost benchmark—and based on RETScreen's calculation that a 45-MMBtu/h biomass boiler can meet 90% of the load currently served by the installation's natural gas central plant (peak times will require an additional boiler)—a savings of about $714,000 per year in heating costs could be realized, as shown in Table 37.

Table 37. Annual Cost Savings of Biomass Heating Versus Original Natural Gas System

Case	Expense	Cost ($K/yr)
Natural gas only heating (original)	Natural gas	$2,437
Biomass base heating plus natural gas peak load system	Biomass fuel	$901
	Natural gas	$261
	O&M+10% contingency	$560
	Total Annual Cost Savings	**$715**

Note that the calculation did not account for any O&M costs for the original natural-gas-fired system or for the natural gas peaking component of the biomass system. Ideally, these costs would be estimated and included as part of the economic analysis, which should improve the feasibility of the biomass system. Table 38 summarizes the RETScreen-calculated fuel use and annual contribution of each system to the system heating demand. Note that the RETScreen units for biomass (tons) are dry metric tons per year.[59] This would equate to 17,100 dry short tons and 26,300 green short tons (at 35% moisture content, 17,100/(1-.35) = 26,300).

[59] RETScreen's biomass fuel units are a potential cause of confusion. One metric ton = 1,000 kg, which is approximately 2,205 pounds. One short ton = 2,000 pounds. Thus, 1 metric ton is about 1.1 short tons.

Table 38. Contribution of Biomass System to Annual Heating Energy Use

Proposed Case System Summary	Fuel Type	Fuel Consumption	Unit	Capacity (MMBtu/h)	Energy Delivered (MMBtu/yr)
Base Load	Wood waste – mixed softwood	15,500	Dry metric tons/yr	45	255,000
Peak Load	Natural gas	43,700	MMBtu/yr	40	30,600

Using the cost charts above and other data, we estimated a total capital cost of $4.1 million, including:

- $2.7 million for fuel handling and storage equipment, the biomass burner and boiler, pumps, controls, emission control systems, ash handling systems, and fire safety systems
- $0.6 million for engineering, design, shipping, and spare parts
- $0.6 million for contingencies (20% of above costs)
- $0.2 million for interest during construction (at 8% for 18 months—a conservative estimate).

As discussed above, we assumed that non-fuel O&M costs were proportional to thermal energy produced, and used a value of $2 per million Btu, which is about $510,000 per year ($2/million Btu x 255,000 MMBtu/yr energy delivered = $510,000/yr).

Economic Analysis

Based on estimated capital and O&M costs, RETScreen calculated that the simple payback period for this project would be about 6 years, and the NPV would be $7.8 million, as shown in Table 39 below.

Table 39. Economic Summary for a Biomass Heating System

Parameter	Units	Value
Delivered Cost of Natural Gas	$/MMBtu	5.98
Blended Delivered Cost for Biomass	$/green ton	34.26
Annual Natural Gas Displaced	MMBtu	364,000
Annual Natural Gas Cost Savings	$/yr	$2,176,000 [60]
Additional O&M (including contingency)	$/yr	$560,000
Annual Biomass Fuel Cost	$/yr	$901,000
Capital Cost for New Plant	$M	$4.1
Simple Payback	years	5.8

[60] This is just the reduction in natural gas expenditures: $2,437,000 - $261,000 = $2,176,000.

The investment costs as outlined in the ECIP form are shown in Table 40 below.

Table 40. Biomass Example Investment Costs

Parameter	Value	Notes
Construction Cost	$4,100,000	
SIOH (5.7%):	$233,700	Calculated automatically in ECIP worksheet
Design Cost (4%)	$164,000	Calculated automatically in ECIP worksheet. However, most of the quoted prices for RE already include design costs, so energy managers should consider removing the additional 4% design cost for their project or reducing the construction cost estimate by 4% so that design costs are not counted twice.
Salvage Value of Existing Equipment	$0	
Public Utility Company Rebate	$0	
Total Investment	$4,497,700	Calculated automatically in ECIP worksheet

The energy savings entered in the ECIP form are shown in Table 41 below.

Table 41. Biomass Example, Energy Savings in ECIP Form

Parameter	Value	Notes
Natural Gas Cost	$5.98/MMBtu	
Natural Gas Savings	364,000 MMBtu/yr	
Natural Gas Cost Savings	$2,176,720	Calculated automatically in ECIP worksheet
Biomass Cost	$2.96/MMBtu	Assuming moisture content of 0.35, biomass cost is calculated as: (8,900 Btu/dry lb) x (1-0.35) dry lb/green lb x (2,000 lb/green ton) x 1 MMBtu/1,000,000 Btu = 11.57 MMBtu/GT ($34.26/GT) / (11.57 MMBtu/GT) = $2.96/MMBtu
Biomass Savings	-305,755 MMBtu/yr	255,000 MMBtu/yr delivered / 0.84 availability= 305,000 MMBtu/yr
Biomass Savings	-$905,036	Calculated automatically in ECIP worksheet
Natural Gas Discount Factor	22.63	Based on 25-year discount factor for natural gas in Colorado
Biomass Discount Factor	17.59	Based on 25-year discount factor for distillate oil in Colorado, this can be used as a proxy for a biomass discount factor
Discounted Natural Gas Savings	$49,259,174	Calculated automatically in ECIP worksheet
Discounted Biomass Savings	($15,919,583)	
Total Savings	$33,339,591	Calculated automatically in ECIP worksheet

The O&M costs are entered as non-energy costs in the ECIP form as shown in Table 42 below.

Table 42. Biomass O&M Savings in ECIP Form

Parameter	Value	Notes
Annual Recurring	($560,000)	
Discount Factor	17.41	Based on discount factor for finding the present value of annually recurring uniform costs (non-fuel)
Discounted Cost	($9,749,600)	

The system economics are summarized in the ECIP form as shown in Table 43 below.

Table 43. Biomass Example, Summary in ECIP Form

Parameter	Value	Notes
First-Year Dollar Savings	$711,684	Calculated automatically in ECIP worksheet
Simple Payback	6.3	Calculated automatically in ECIP worksheet
Total Net Disc. Savings	$23,589,991	Calculated automatically in ECIP worksheet
SIR	5.24	Calculated automatically in ECIP worksheet

For this example, the SIR is greater than 1, and the project would also need to score well in all of the non-energy savings/economics categories to be approved for funding.

Training

The National Training & Education Resource (NTER) offers an RE curriculum via webinar from the DOE Office of Indian Energy. This webinar includes a biomass module and is available for free with registration at: https://www.nterlearning.org/web/guest/course-details?cid=405.

Army Bases That Have Successfully Installed Biomass Systems Funded by ECIP

While Army installations have installed biomass technology demonstrations, there are no known ECIP-funded biomass installations in the Army.

In November 2012, Coast Guard Air Station Sitka installed a wood pellet heating system to displace $4/gal heating oil. Sitka was the first Coast Guard station to switch to pellets—though Coast Guard Air Station Kodiak has also been long considering a similar switch from oil to pellets.[61] More information on Coast Guard Air Station Sitka's biomass system is available from Bob Deering, Environmental Branch Chief for U.S. Coast Guard Civil Engineering Unit Juneau, at robert.c.deering@uscg.mil.

Montpelier, Vermont, is in the process of building a biomass-fired district heating system for the state government, city government, schools, and portions of the downtown area. This will be an upgrade to an existing wood-fired system.[62]

[61] "USCG readies pellet boiler as Begich tours." (October 8, 2012). KCAW-FM, Raven Radio Foundation, Inc. Accessed June 2013: http://www.kcaw.org/2012/10/08/coast-guard-readies-pellet-boiler-as-begich-tours-in-sitka/.

[62] "District Heat Project." Montpelier, Vermont. Accessed June 19, 2013: http://www.montpelier-vt.org/group/99.html.

WIND TURBINES

Technology Description

Wind turbines have airfoils that translate the force or power in the wind to a rotational force that turns a rotor mechanically. The rotor is attached to a driveshaft that is typically attached to a gearbox or other conversion mechanism to generate electricity. There are two major types of wind turbines that are named based on their orientation: vertical-axis wind turbines and horizontal-axis wind turbines (HAWTs). HAWTs are the turbines most commonly seen in wind applications in the United States and worldwide. Vertical-axis wind turbines have been in use for many years with many different design variations.

HAWTs can range in size from as small as 400 W to as large as 5 MW. Thousands of the smaller turbines are used in applications to provide ranchers, farmers, homeowners, and small-business owners with the ability to generate their own electricity, to partially or wholly replace electricity from the grid. The primary components of a HAWT can be seen in Figure 23 below.

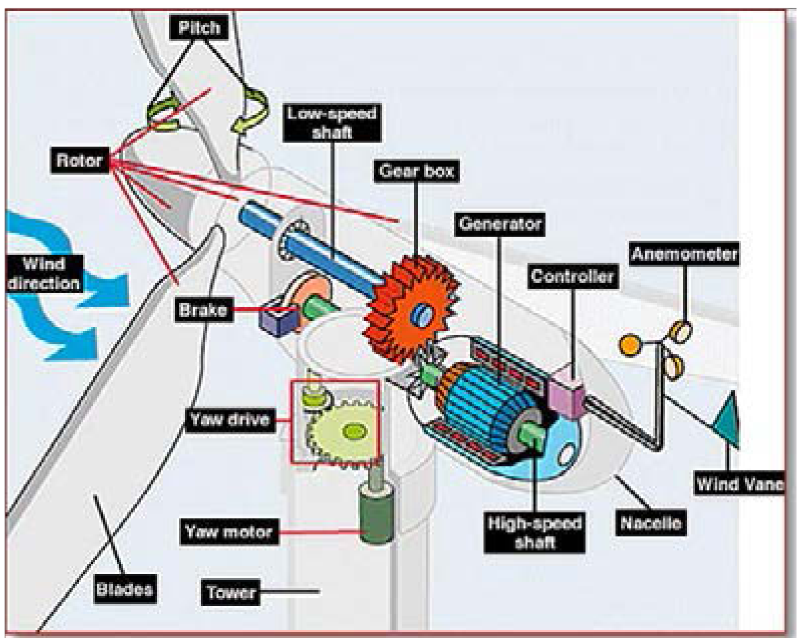

Figure 23. Primary wind turbine components of a HAWT[63]

Wind Power

The amount of wind varies with the season, time of day, and extreme weather events. The wind speed at any given time determines the amount of power available in the wind and subsequently the power that can be captured using a wind turbine generator. Wind power is proportional to velocity cubed (V^3). This is noteworthy because if wind velocity is doubled, wind power increases by a factor of eight ($2^3 = 8$). Consequently, small differences (e.g., increases) in average speed cause

[63] Source: "How Wind Turbines Work." U.S. Department of Energy, Wind & Water Power Program: http://energy.gov/eere/wind/how-do-wind-turbines-work.

significant differences (e.g., increases) in energy production. Therefore, examining ways to increase the wind velocity at different sites should be considered. Primary methods include taller towers and improved micro-siting of the turbine(s).

At many sites, a relatively easy way to increase wind speed is to increase the height of the tower. Typically, wind speed increases as the height above the ground increases. The wind industry has been moving towards ever-higher towers; the industry norm has increased from 30 m to 90 m over the last 15–20 years, and there are installations with 100–120 m towers. With higher towers, there is a trade-off that must be analyzed between increased wind speeds and annual kWh produced vs. increased turbine/tower capital, installation, and O&M costs. Improved micro-siting of the wind turbine can also result in accessing the highest available wind speed at a site. This is accomplished by understanding which direction the most energetic winds come from and siting turbines to avoid the impediments to wind flow (e.g., hills, trees, or buildings) that cause turbulence and reduce wind velocities.

Another approach to increase wind power generation is to increase the dimensions of the rotor. The larger the windswept area of a wind turbine, the more wind power the rotor intercepts, thereby generating more energy and improving the overall project economics. Over the last 4–6 years, turbine manufacturers have been increasing the rotor diameter on wind turbine generator platforms; that is, they are keeping the same rated capacity generator but increasing the rotor dimensions. The result is that the turbine with the enlarged windswept area will collect more energy from the wind and deliver more power and annual energy at a given site. The net impact is that wind energy now becomes economically viable at sites where it was not economic a decade ago.

Wind turbines generally do not produce electricity at low wind speeds fewer than 3–4 m/s (7–9 mph). When there is enough wind to consistently turn the rotor and generate electricity, the turbines “cut-in” into the wind and begin producing power. As the wind speeds increase from the cut-in speed, the wind turbine produces even more electrical power. Typically, somewhere in the 11–14 m/s (25–31 mph) range, wind turbines reach their “rated” or “named” power (i.e., there is an expected wind speed at which a 100 kW turbine will actually produce 100 kW). The wind turbine will generally produce at or near that rated power up to wind speeds of about 25 m/s (56 mph). Above this speed, the turbine will “cut-out” of the wind to avoid damage from over-speeding or overheating.

Wind turbines are typically differentiated by their rated power (i.e., how much power they will produce when there are very energetic winds). How much power a wind turbine produces at any given speed is a function of a number of design functions: how long is the rotor, number of blades, rotor height above the ground, generator converter efficiency, etc. Because power increases as the cube of wind speed, much of the average power available to a wind turbine comes in relatively short bursts during periods of high wind speed. It is only in high winds that the turbine produces at rated power. Though a turbine may be rated at 100 kW at 13 m/s (29 mph), it will produce at 100 kW for only a small fraction of the year—those hours (tens to hundreds of hours per year) when the wind speed is in the range of 13–25 m/s (29–56 mph). The average power produced by a wind turbine over time will be a fraction of the peak or rated power the machine is capable of delivering. Typical utilization rates, or capacity factor (CF), will be 10%–25% for small wind turbines; CF values are usually higher (30%–50%) for utility-scale wind turbines.

Project Development Considerations

The wind development process is a multi-step endeavor that requires considerable effort and experience to accomplish successfully. Commercial wind developers typically expect to take 5–7 years to develop a project in the 50–300 MW range. Many of the activities can be addressed concurrently, after initial scoping and fatal flaw analyses are complete.

WIND TURBINES

There are some aspects of the commercial process that are comparable to what the Army would expect at a military base or other property. There are also some unique considerations at military bases that require special consideration. Areas that include military training grounds and facilities, or that host critical radar or telecommunication devices, present siting challenges beyond what a developer typically encounters in rural farming communities.

Key project development considerations for siting, system design, estimating savings, and policies and permits are presented in this section.

Siting

Site Selection

There are several key aspects of siting that are intertwined with some of the other wind development steps. In siting a meteorological (met) tower, it is important to put it in a location where there is a high likelihood of a wind turbine being installed in the future. Picking the “windiest location on base,” even though it is known that a turbine will not be allowed there, will inform as to the “maximum wind resource” on base, but it will not help discern what actual expected turbine performance will be, as the amount of variation from the maximum to realistic sites will be unknown.

The intent in site selection is to determine the windiest buildable location that will optimize the combination of:

- Minimum distance to the electrical tie-in
- Reasonable road surfaces (may require upgrade for increased width, wider turn radius, or increased load bearing capability) for bringing in large, heavy equipment
- Ample room for cranes and lay-down area for large turbine blades and tower sections.

Mission Impact

It is expected that the majority of Army ECIP wind projects will encompass one to five utility-scale wind turbines. The actual land needed permanently for the turbine foundation(s) is minimal, though the impact on air or ground operations may be considerably larger than the turbine foundation footprint. Impact on the land will range from the initial phase focused on wind resource assessment, possibly with a 50- to 80-m met tower to the construction phase with lots of heavy equipment onsite, possibly even a batch concrete plant. When complete, the project will usually consist of turbines with a concrete pad foundation at the base, roads connecting the turbines, and distribution/transmission wires, most often laid underground. For most Army installations, it is envisioned that the land agreement shall be relatively easy to execute contractually if there can be agreement among affected parties regarding potential impacts to onsite Army operations such as flight paths, training grounds and activities, radar, etc.

Road Access

For smaller turbines, road access is typically not an issue. At sites where the Army is considering a large wind turbine project, adequate access for large wind turbine component shipments (tower sections and blades) and heavy construction equipment (cranes) needs to be fully investigated. It is likely that the site energy manager, and even the site transportation manager, has never dealt with any equipment of this size before. Turning radius, slope, and surface roughness are all considerations that need to be fully investigated before components are shipped to the site.

For larger projects, wind developers look for roads that are usable “as is” for large wind turbine component shipments (tower sections and blades) and heavy construction equipment (cranes) for approaching the general wind farm site. Specific road construction to each turbine site is often part of the construction process.

Wind Resource Assessment

Wind resources are site specific. Different sites in close proximity to each other, but with varying vegetation (i.e., tall trees vs. grassland or cropland), topographical features (e.g., ridges vs. valleys; canyons vs. mountains), and surface roughness (i.e., city skyscrapers vs. flat or rolling farmland), may have entirely different wind regimes. One may prove to be economic, and one may not.

Windiness varies with the season and time of day and, of course, weather events. Collected wind data focus on two primary considerations: average annual wind speed, and a frequency distribution of the wind at various speeds. The wind speed at any given time determines the amount of power available in the wind.

Wind maps are useful for determining from a high-level view where the wind usually blows. The Wind Powering America (WPA) program maintains a website with high-quality, color-coded wind maps as seen below.[64] The online map is interactive, so the user can obtain enlarged maps of each state and estimates of the wind resource at 30-, 50-, and 80-m above the ground.

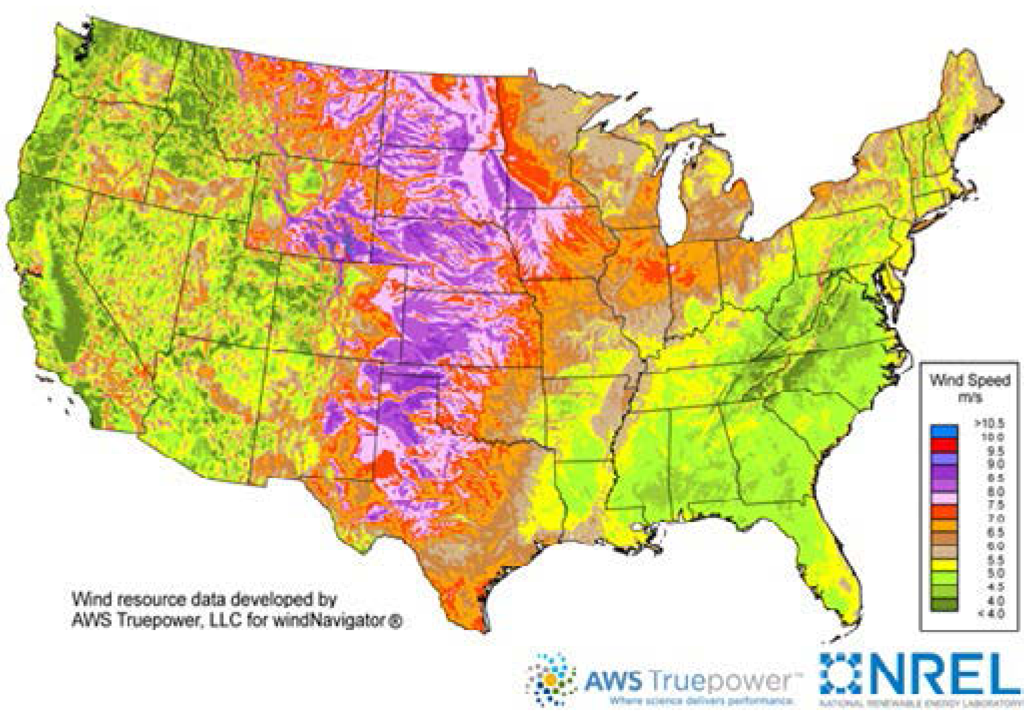

Figure 24. U.S. wind speed map at 80 m

Wind maps are not used to site large wind turbines/farms, as they are not sufficiently accurate. Generally speaking, wind maps are only used in the "prospecting" phase of wind turbine project development to determine potential locations where studying the wind in more detail through the use of a met tower, equipped with anemometers and wind vanes, is merited.

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[64] "Utility-Scale Land-Based 80-Meter Wind Maps." WINDExchange. U.S. Department of Energy. Accessed March 12, 2015. http://apps2.eere.energy.gov/wind/windexchange/wind_maps.asp.

WIND TURBINES

The intent of a wind resource assessment is to fully understand the wind resource at the site of interest. The rule of thumb with wind is to know, as much as economically possible, the extent of the wind resource and the likelihood of an economically successful project before investing in and installing a wind turbine. The type of wind assessment undertaken depends on the expected size and cost of the wind turbine(s).

For large wind farms or utility-scale turbines (1–3 MW/turbine), a full year-long assessment utilizing a 60–80 m met tower fully instrumented with anemometers and wind vanes at several heights is typically undertaken, as the investment is substantial and ensuring viable economics is critical. A single met tower with a year of data collection, analysis, installation and takedown may cost in the range of $50,000–80,000. A wind farm might require two to 10 met towers depending on its size, the terrain, and wind flow patterns and variations. For wind farms, several 80-m met towers are typically deployed across the proposed wind farm with the aim to select the sites most representative of the sites where turbines will be installed. Due to higher costs associated with the purchase and installation of an 80-m met tower, for projects with one to three wind turbines, a single met tower in the 50–60 m range is commonly used. An advantage of these shorter towers is that they are below the height (200 ft or 61 m) requiring Federal Aviation Administration notification and permitting.

The industry standard is to install a 50–80 m met tower, record and analyze the data for 12–24 months, then correlate the data to a long-term reference station to determine if the data collected represent the best wind year in the last five, the worst wind year of the decade, or an average wind year, and adjust the collected data accordingly. Without correlation, the 1–2 years of collected data has limited value as wind speeds and duration can vary appreciably from year to year. The collected data "normalized" to the long-term trends is considered the most reliable method to predict wind turbine(s) performance over the 20-year useful life of the turbine(s). The wind assessment will also discern key wind characteristics such as:

- Vertical wind shear
- Turbulence
- Diurnal wind patterns
- Seasonal wind patterns
- Wind direction—wind direction vs. wind power density, wind direction vs. time of day, wind direction vs. time of year.

Met Towers

Met towers are still the most common method deployed for onsite wind resource assessment. The met tower may be temporary or permanent. Temporary met towers are typically supported by one to three sets of guy wires extending out in four directions (i.e., north, south, east, and west) with screw-in or arrowhead anchors (most common). The guy wires for a 60-m tower normally extend out 50 m from the tower base in four directions. The towers are intended for installation on land with a slope of fewer than 10°.

The met tower is equipped with anemometers to measure the wind speed, wind vanes to record the wind direction, and a temperature sensor to track the temperature. The met tower may also include a barometric pressure sensor to record atmospheric pressure. There are usually redundant anemometers at several levels: just below the top of the tower, 8–15 m below the top, and 20–30 m below the top. A wind vane is usually placed below the top and bottom level of anemometers. The temperature and barometric pressure sensors are set 1–2 m above the ground.

For a permanent met tower, a lattice tower is typically used, with or without guy wires (depending on the extreme winds) and with a concrete foundation in the ground (Figure 25). Monopoles without guy wires can be used as well, but are typically prohibitively expensive for wind resource assessment activities, particularly for a project with one to three wind turbines.

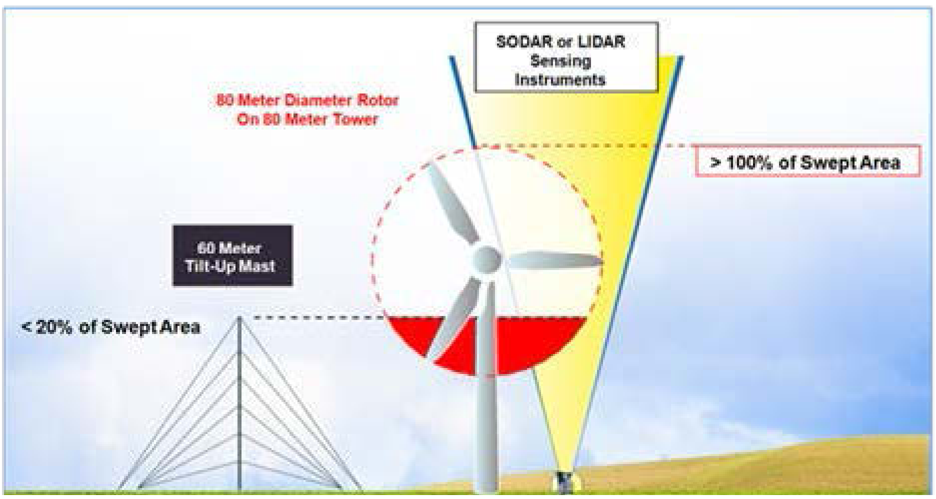

Figure 25. Schematic of a met tower with guy wires[65]

Wind Resource Assessment Options

Wind resource assessments take time and money to complete. The amount of time and money the Army should spend on the resource assessment part of a wind project is largely dependent on the ultimate cost and size of the intended project. Installing a 60-m met tower for 12–24 months is considered a standard, prudent approach for assessing wind for a 1 MW or larger project. It is wasteful to spend that amount if considering only a 10-kW turbine, when freely available mapped estimates or a purchased dataset may suffice. Table 44 below provides guidance for assessment approaches given potential project size and cost range. Some states, including Texas, North Carolina, Maine, and Illinois offer free anemometer loan programs.

[65] Source: Elliot, D., Wind Resource Assessment presentation, BLM Wind Energy Applications Technology Symposium, NREL, Golden CO, August 2010.

Table 44. Estimated Wind Assessment Costs and Recommendations for Wind Projects of Various Sizes

Project/ Turbine Size (kW)	Project Cost Range ($)	Time Frame for Assessment [Month(s)]	Assessment Recommendation	Estimated Cost of Assessment
1–10	$6,000–$80,000	1	$6,000–$20,000—map and free data	$0
		2–3	$20,000–$80,000—purchase validated dataset	$3,000–$8,000
10–50	$60,000–$300,000	2–3	$60,000–$300,000—purchase validated dataset	$8,000–$20,000
		15–20	$60,000–$300,000—free met tower (20–50 m) loan program	
50–500	$300,000–$2.5 million	15–20	50–60-m met tower loan or purchase	$20,000–$70,000
500–2,000	$2.5 million–$10 million	15–30	60–80-m met tower and/or Sonic Detection and Ranging (SODAR)	$50,000–$200,000
2,000–50,000	$7 million–$150 million	15–30	2–4 60–80 m met tower and/or SODAR	$100,000–$500,000

Proximity to Distribution/Transmission Line Interconnection

To be cost effective, the distance between the wind turbine and the point of interconnection, typically on the customer side of the meter, should be minimized. Each site and project will need to determine if it is required or if it makes more sense to do an underground vs. above-ground distribution.

On the larger scale, as wind (and solar) continue to develop, particularly in the west, availability for new generating capacity on existing transmission lines has become an increasing concern. This first-cut view might be expanded to include "potential for transmission line development" in lieu of proximity to transmission lines.

Policies and Permits

There are several types of permitting that will apply to any Army wind turbine project. The Federal Aviation Administration, Department of Defense (Army), and the Next Generation Weather Radar (NEXRAD) weather services all have an interest in the impacts of any wind turbine project. Army, with NREL assistance available, can apply online with the turbine(s) location, tower height, and rotor diameter specifications at: https://oeaaa.faa.gov/oeaaa/external/gisTools/gisAction.jsp?action=showLongRangeRadarToolForm.

Local or Army base building permits are also necessary, as turbine installation is a full-scale construction activity.

Federal Aviation Administration

All wind turbines with rotor height over 60 m (approximately 200 ft) are subject to approval by a series of federal agencies with responsibilities for airspace and flight operations. These agencies are listed in Table 45.

Table 45. Radar and Regulating Authority

Type of Radar Operation	Federal Agency
Defense Radar & Military Training Routes	Department of Defense
Next Generation Weather Radar Program (NEXRAD)	Departments of Commerce, Defense, and Transportation
Long-Range Radar and Airport Runways	Federal Aviation Administration

DOD has established the DOD Siting Clearinghouse to review the compatibility of wind, solar, transmission, and other projects with military activities. Developers can request a preliminary determination by providing the project location, number of turbines, turbine type, hub height, blade tip height, and turbine farm layout. Instructions for requesting a review are provided on the DOD Siting Clearinghouse website.[66]

There may be state agencies or offices with permitting requirements or siting responsibilities in regards to wind turbine projects. These may include state historic preservation offices, natural resource and environmental protection agencies, public utility commissions, or construction or industrial development agencies.

There are also transportation permits for delivering via road or barge the wind turbine blades and tower sections. These arrangements need to be made well in advance of any of the equipment being shipped to the base.

Operations & Maintenance

Wind turbines require regular maintenance. Manufacturer warranties typically cover the first 2–5 years. Often, these O&M agreements can be extended to 5 or even 10 years. Professional wind turbine maintenance contractors (also known as windsmiths) are recommended after the warranty period with the manufacturer has ended.

Key considerations for an O&M agreement include:

- Frequency and time involved in routine maintenance
- Special skills or training required to service equipment
- Costs associated with maintenance
- Discussion of controls and remote monitoring
- List of components that need to be refurbished or replaced during system life.

Metering

Per Army policy, advanced meters must be installed on all ECIP projects and connected to the MDMS.[67] Wind energy monitoring systems come standard with most installations and should be specified in the contract to ensure proper operation and energy production in out-years.

[66] http://www.acq.osd.mil/dodsc/contact/dod-review-process.html

[67] Army Directive 2014-10 (Advanced Metering of Utilities), dated 4 June 2014, Section 3.b(5).

Estimating Wind Capital Costs and O&M Costs

Wind turbine price trends over the past 30 years can be seen in Figure 26 below. After two decades of steadily declining prices, the wind industry experienced the 2000s with steadily increasing prices, as worldwide demand for wind turbines soared while commodity prices for steel, copper and concrete generally rose. The recession, which began in 2008, has impacted the wind turbine market, but due to the long-term nature of wind turbine procurement contracts (typically 12–24 months) there was a time lag of about 18–24 months before the recession impacts began to impact the market in earnest. Ongoing research and development aims to continue the downward trend for installed cost of wind turbines.

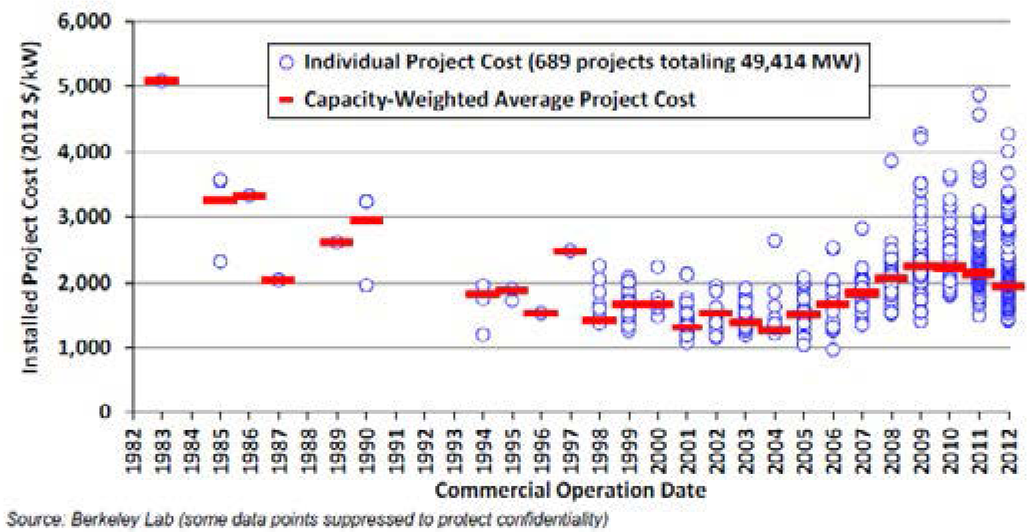

Figure 26. Installed wind power project costs over time[68]

As seen below in Figure 27, there is a significant premium (approximately 15%–20%) for wind turbine projects smaller than 5 MW. It should be noted that the overall price spread between projects in this size range is greater than most of the other size ranges. There are many individual, site-specific factors (e.g., wind turbine size, region of the country, and soil/foundation requirements) that contribute to this very wide price spread. For this reason, it is better to consider a price range for installed turbine costs for initial scoping, rather than a single figure. As more project details become known, the price range can be narrowed.

[68] Source: Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, D.C.: Department of Energy. Accessed May 2014: http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf.

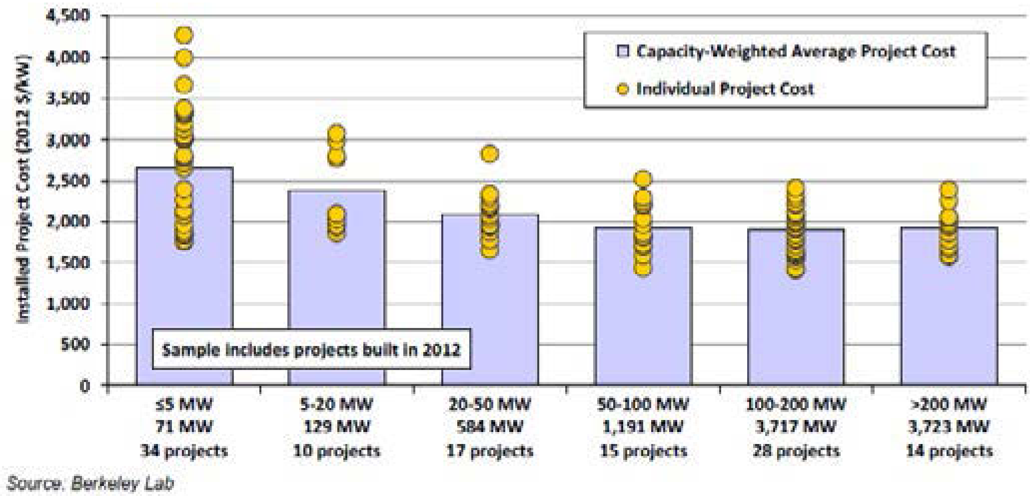

Figure 27. Installed wind power project costs by project size: 2009–2011 projects[69]

Also of note, as shown in Figure 28, smaller turbines (100–1,000 kW) are significantly more costly per kW than turbines rated at 1 MW and larger.

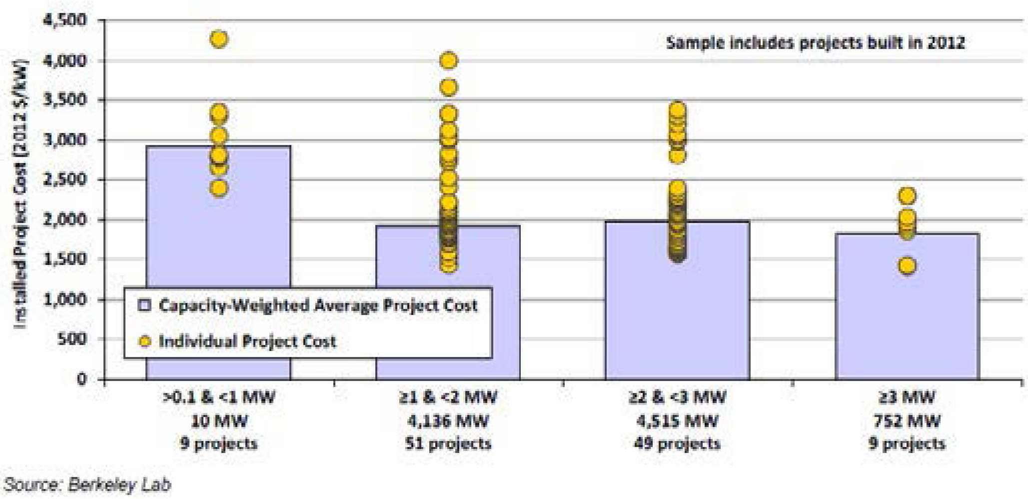

Figure 28. Installed wind power project costs by turbine size: 2009–2011 projects[70]

There is significant variation in installed turbine costs in different parts of the country, as can be seen in Figure 29 below. Project size, soil types, permitting, etc., all play a role in the regional variation.

[69] Source: Wiser, R.; Bollinger, M. Ibid.

[70] Source: Wiser, R.; Bollinger, M. Ibid.

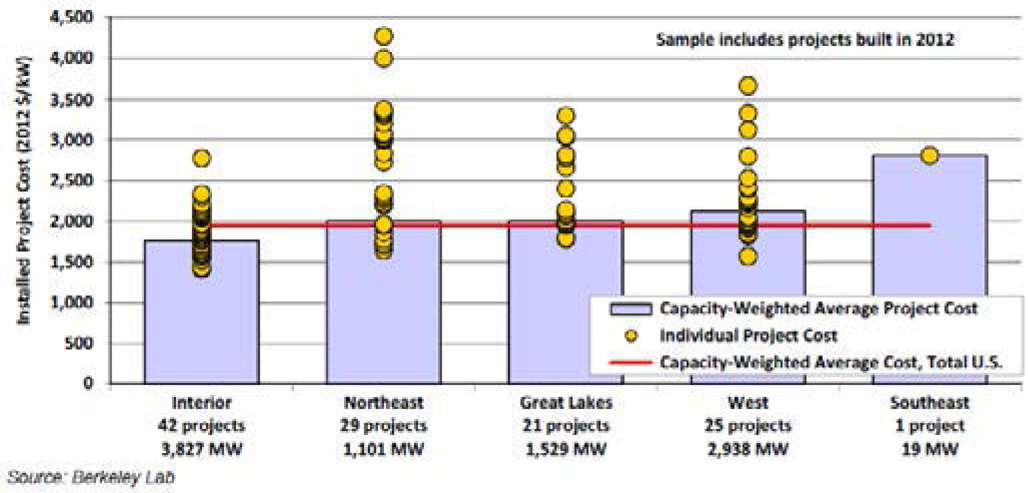

Figure 29. Installed wind power project costs by region: 2012 projects

Generally speaking, it is anticipated that most Army wind projects will be in the size range of one to five utility-scale turbines due to limited available land on base, potential runway operation impacts, radar impacts, explosive arc issues, etc. In the absence of these constraints, more turbines may be possible. The installed capacity is best sized to deliver less than the annual electric load of the base so that most or all of the wind electricity produced will be used to offset electricity purchases at retail rates from the utility. While retail rates may vary, they can be 40%–120% higher than wholesale rates.

The economics of projects with one to three wind turbines are quite different than for 100–300-turbine wind farms, and the two should not be confused. Installed costs for large wind farms are in the range of $1,300–2,500/kW. The average installed cost per kW increased roughly 11% per year from 2007–2009, and then decreased 3%–5% through 2012, with average installed costs increasing from $1,700/kW to $2,100/kW over this timeframe. Installed costs for projects with one to three utility-scale turbines are difficult to reliably come by because, though published project cost numbers may be available, the exact construction and component costs included in these figures tend to vary considerably and are generally not detailed. Extrapolations made from published figures may lead to unreliable cost estimates. Smaller turbines (50-100 kW) are considerably more expensive on a dollar per watt basis, approximately $5,000-8,000/kW.[71]

Capital Costs

A breakdown of the cost components of installed costs for utility-scale wind turbines is shown in Table 46 below. Due to the price variability discussed above, the breakdown is given for a range of installed cost figures. The data shown have been re-arranged from the source document for readability/grouping purposes. The average installed cost for a land-based 1.5 MW wind turbine in 2011 was $2,098/kW[72] for the 2,630 MW of installed wind turbine cost data collected that year. If construction financing ($60/kW) were excluded, the average cost would be $2,038/kW, which aligns with the 2011 cost figures cited in Figures 26–29.

[71] See Figure 16, 2013 Small Wind Turbine Installed Costs, in DOE's 2013 Distributed Wind Market Report: http://energy.gov/sites/prod/files/2014/09/f18/2013%20Distributed%20Wind%20Market%20Report.pdf.

[72] Tegen, S., Lantz, E., Hand, M., Maples, B., Smith, A., Schwabe, P. 2011 Cost of Wind Energy Review, National Renewable Energy Laboratory, Technical Report NREL/TP-5000-56266, March 2013.

Table 46. Installed Utility-Scale Wind Turbine Component Cost Estimates in Various Cost Ranges

Wind Turbine Cost Scenarios	$3,000/kW	$3,500/kW	$4,000/kW
Direct:			
Turbine Cost	$1,894	$2,210	$2,525
Foundation	$106	$124	$141
Electrical	$218	$254	$290
Subtotal - Direct	$2,218	$2,587	$2,957
Indirect:			
Engineering, Procurement, Construction	$81	$95	$108
Project, Land, Miscellaneous	$521	$608	$695
Transmission and installation	$180	$210	$239
Subtotal – Indirect	$782	$912	$1,043
Total Installed Cost	$3,000	$3,500	$4,000

O&M Costs

Average O&M costs of $35/kW/yr were cited in the 2011 Cost of Wind Energy Review.[73] This represents a $7/kW/yr decline from the 2010 O&M average. There are substantial research and development investments aimed at reducing O&M costs. The trend shown is indicative of the success of these efforts. There is no available data on single-turbine O&M costs, though it is reasonable to assume these contractual costs may run between $40/kW/yr and $50/kW/yr during the 2–5 year warranty period. Beyond that, O&M will also include a variable component representing the actual repair costs for events outside of routine O&M.

Large wind farms (50 MW and larger) typically have permanent O&M staff onsite that perform both routine maintenance and address non-routine issues as they come up. All of the turbines are monitored individually, and the operating conditions (e.g., wind speed, rotor rpm, fluid temperature, and particulate density) are typically viewed both locally and at the manufacturer's headquarters. The intended result is near-real-time awareness of operating conditions and the potential to address minor issues before they become major issues thereby lowering O&M costs. In the event of a component failure that requires technical servicing, the goal is to minimize cost by optimizing cost factors such as procurement time for parts and specialized equipment (e.g., cranes), lost revenue from turbine downtime, ability to cost share expensive equipment (e.g., cranes) across multiple repairs, etc. (Figure 30).

[73] Tegen, S., et al, Ibid.

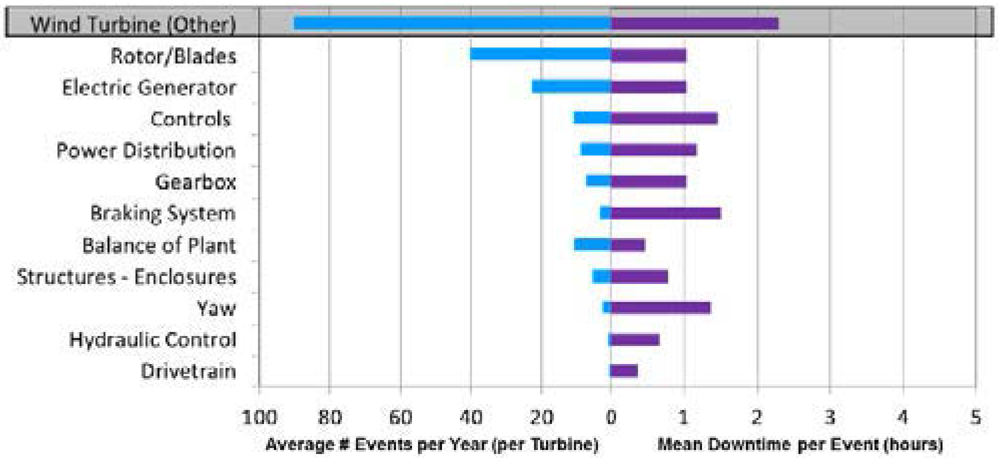

Figure 30. Wind turbine annual failure rate and downtime per event[74]

Source: Sandia National Laboratories Continuous Reliability Enhancement for Wind (CREW) database

Because the O&M figures cited are aggregated from wind farm-sized projects, these costs will be higher for projects with one to three turbines. On the one hand, there is no permanent staff onsite, so that contributes towards lowering the costs. However, every issue that demands a trained technician to address will require mobilization (e.g., transport, hotel, and per diem) plus time and materials to repair. Turbine downtime may be significant and add cost and urgency to the repair.

There are several approaches to consider for reducing O&M costs for projects with one to three turbines, including the following:

- In evaluating turbine procurement options for one to three large turbines, consider purchasing from the same company that already has a number of operating wind turbines within 1–300 miles. In this way, it can be easier to obtain a reasonable price for an O&M contract, as servicing can be accomplished by technicians who are already in the vicinity of the Army wind project, thereby lowering travel costs and simplifying scheduling.

- Keep a ready supply of replacement parts on hand so that, in the event of a component failure, waiting for parts can be taken out of the time to repair timeframe.

The O&M contract costs are turbine- and site-specific and are negotiable with the O&M providers. Some contractors are beginning to target the single-turbine market for O&M services. Over time, the cost and quality of these services will become more widely known and may serve Army projects with one to three turbines well in the future.

[74] Sheng, S., Report on Wind Turbine Subsystem Reliability – A Survey of Various Databases, NREL/PR-5000-59111, June 2013.

Estimating Energy Production

Energy production can be estimated with one of the following free software tools:

- RETScreen: http://www.retscreen.net
- Solar Advisor Model: https://sam.nrel.gov
- HOMER: http://homerenergy.com/HOMER_legacy.html

Specific turbines with selected hub heights and rotor diameters can be selected, and turbine performance results are calculated accounting for elevation impacts (air density decreases with altitude), turbine spacing, etc.

Project Economics

Wind project economics are not dictated by the wind resource alone. Also of critical concern is the cost of the electricity wind is competing against. The theoretical wind viability curve in Figure 31 illustrates the relationship of the mean annual wind speed to the cost of the electricity the wind is competing against. This is not an exact curve; it is a representation of the relationship between critical factors. The higher the cost of competing electricity (e.g., northeast United States), the lower the mean wind speed can be while still being economically viable. Likewise, in areas with very low cost of electricity (Pacific Northwest, Upper Midwest) it takes a higher mean wind speed to have an economically viable project. Generally speaking, sites with low wind speeds and low competing cost of electricity (the region below the viability curve) will not be economic. Likewise, sites with higher wind speeds and higher cost of electricity (above the cost curve) will be economically viable.

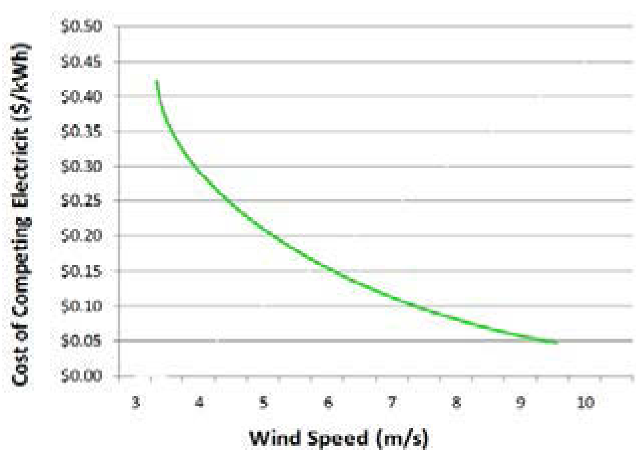

Figure 31. Cost of competing electricity vs. wind speed curve

Another key factor in evaluating the potential of a wind project is the frequency distribution of the wind resource (Figure 32). Mean annual wind speed is most often used as a common denominator indicative of how strong the wind resource might be. Of greater critical importance is a more discrete breakdown of how many hours per year the wind blows at certain speeds, as that directly determines how much electricity a wind turbine will produce at a specific site in a given or average wind year.

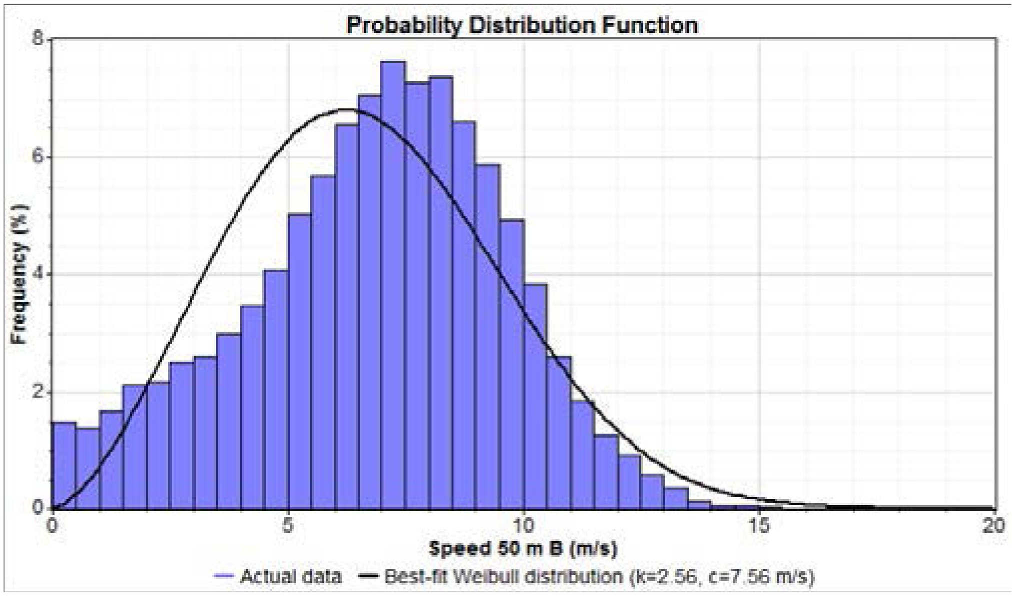

Figure 32. Graphic example of an annual wind speed distribution
Illustration by Robi Robichaud, NREL

Example Calculation

Back-of-the-envelope calculations are not recommended for potential wind projects, as the variability and uncertainty in the project factors, as outlined above, are often enough to impact the initial "go/no go" decision before adequate project data have been collected. If an installation has a general wind resource and electric rate that looks favorable for a wind project, then a wind consultant well versed in wind project development considerations should be hired to develop ECIP wind projects.

Training

There are a variety of free educational resources on wind available (Table 47). There are also workshops, seminars, etc. A brief, non-exhaustive list is provided below.

Table 47. Wind Energy Training and Resources

Source	Outline	Topics	Date	Location	Register/Information	Cost
WINDExchange/ DOE/NREL	Series of webinars on current wind energy issues. Audiovisual text versions available.	Technology advancements; Certification standards; Wind and solar integration; Distributed wind	Monthly; Archived webinars available online	Online	http://apps2.eere.energy.gov/wind/windexchange/podcasts_webinar.asp	Free to registrants
American Wind Energy Association (AWEA)	Seminars and webinars on current activities in the wind industry	Wind development; Market trends; Business strategies; Research findings	Periodic	Seminars/ workshops-various locations; Webinars online	http://www.awea.org/Events/Eventslist.aspx	Varies
Windustry	Community wind; home and farm scale	Wind project development-step-by-step outline	Online	Online	http://www.windustry.org/wind-basics	Free
ERDC-CERL	Report on method for assessing wind turbine compatibility	Small Wind Turbine Compatibility with Army Installations	August 2013	Online	http://el.erdc.usace.army.mil/elpubs/pdf/trel13-4.pdf	Free

Army Bases That Have Successfully Installed Wind Turbines Funded by ECIP

The current federal fleet of wind turbines is about 47 MW, with 36 MW on military bases. The estimated capacity of Army wind turbines is 2.4 MW installed. See Table 48.

Table 48. Installed Wind Capacity on Army Bases per NREL Tally

Agency	Federal Wind Sites	# of Turbines	Turbine Rated Power	Plant Capacity	Install Year
		[#]	[kW]	[kW]	[Year]
Army National Guard	Camp Williams, Riverton, UT	1	225	225	2000
Army National Guard	Camp Williams, Riverton, UT	1	660	660	2005
Army	Tooele Army Depot, Tooele UT	1	1500	1,500	2012
Army	Fort Buchanan, Puerto Rico	3	275	825	2013
	Total	**3**		**2,385**	

Contact information for Camp Williams, Tooele Army Depot, and Fort Buchanan is provided in Table 49.

Table 49. Wind System Base Contacts

Name	Installation	Title	Phone	Email
Ricy Jones	Camp Williams, Riverton, UT	Energy Manager	801-432-4459	ricy.jones.nfg@mail.mil
Royal Rice	Tooele Army Depot, Tooele UT	Energy Manager	435-833-3777	royal.d.rice.civ@mail.mil
Anibal Negron	Fort Buchanan	Environmental Chief	787-707-3575	anibal.negron1.civ@mail.mil

APPENDIX A: UTILITY ELECTRIC BILL CHARGES

The various types of charges on an electric bill are outlined below:

- ***Fixed Monthly Charge ($/Month)*:** Each electric meter at the site will have a fixed monthly meter fee charge ($/month), and this charge should be subtracted from the charges used to calculate the total rate as no RE project will reduce the costs of the fixed monthly meter fee.

- ***Demand Charge ($/kW)*:** Most commercial and industrial rate structures include a demand charge, and most smaller residential rate structures do not. The site should look at the bill and see if there are demand charges in units of $/kW. If a demand charge is present, it is typically recorded once a month as the highest peak power (i.e., demand) recorded over a 15-minute interval over the given billing period (which is usually a month). If these charges are present, then the site needs to collect the monthly demand and associated monthly demand charges, in addition to the monthly energy usage and cost. RE projects do not always reduce peak demand and hourly modeling of load and renewable generation is recommended to accurately estimate peak demand reduction.

- ***Energy Rates ($/kWh)*:** Reductions in energy charges are often one of the primary sources of savings from a RE project. The installation's type of energy rate needs to be considered when calculating potential energy savings. Some common rates are described below:

    - ***Flat Rate*:** A flat electricity rate does not change throughout the day, but may change seasonally. For example, the utility might have a summer and winter rate structure. A flat rate is billed based on the amount of electricity used over the billing period and has units of dollars per kilowatt-hour ($/kWh).

    - ***Block Charge Rate*:** A block charge can be applied to both energy/electricity rates and demand charges, and can be either inclining or declining within a set "block" of energy use or power consumption. For example, smaller facilities often have block charges that increase the utility rate for every 1,000 kWh of energy used (as an example). In this case, the energy rate might be $0.10/kWh for the first 1,000 kWh and $0.12/kWh for the next 1,000 kWh used that month; this would represent an inclining rate structure.

    - ***Ratchet Rate*:** Ratchet rates may be applied to demand charges if a site has a ratchet rate structure. The highest monthly demand over any given month becomes the annual peak, which is used to ratchet the monthly demand peaks for the next 11 months. For example, if the peak demand for last summer was 500 kW and there is a 50% ratchet, the minimum billing would be 250 kW for the following months, regardless of how low the actual demands were.

    - ***Time-of-Use Rate*:** Time-of-use rates are most common in California and are slowly being adopted by other utilities throughout the country. Time-of-use rates are applied to both energy and demand rates, and a given rate changes based on the month, day of week, and time of day. These rate structures further complicate the process of calculating cost savings from a RE project, as the economic benefit of the energy production is based on the time of day, day of the week, and month of the year that the system is producing electricity.

    - ***Real-Time Pricing*****:** Some utility markets have moved to real-time spot market pricing for general energy and demand charges. The charges are typically coupled with fixed transmission and distribution charges. This rate structure is more complex than others, as the electric energy and demand rate changes every hour of every day throughout the year.

- ***Power Factor Costs*****:** Utilities usually charge commercial and industrial customers a power factor charge for poor power factor. Some rates are set up where the customer gets billed on a $/kilovolt-ampere reactive (kVAR) basis for every kVAR below unity, and others are set up to charge the customer if the power factor falls below a predefined threshold, such as a power factor of 0.95. System integrators should pay close attention to power factor when installing a RE system, and newer inverters that are capable of improving onsite power factor should be considered for both PV and wind projects.

APPENDIX B: DD FORM 1391 SPREADSHEETS AND RETSCREEN FILES

The DD Form 1391 spreadsheet files for each of the technology example calculations and the RETScreen files used in the SHW, SVP, GSHP, and biomass example calculations are included as attachments in this electronic PDF.

Click to show the following spreadsheets:

- Biomass 1391.xls
- GSHP 1391.xls
- PV 1391.xls
- SHW 1391.xls
- SVP 1391.xls
- RETScreen_Biomass.xlsm
- RETScreen_GSHP.xlsm
- RETScreen_SHW.xlsm
- RETScreen_SVP.xlsm

APPENDIX C: POTENTIALLY COST-EFFECTIVE ARMY RE PROJECTS IDENTIFIED IN PRELIMINARY RE SCREENING

NREL conducted a preliminary screening of PV, SHW, SVP, biomass, and wind opportunities at 87 Army installations. This appendix provides information on projects identified as potentially cost effective at these installations. The projects identified here could be considered for further analysis to determine whether they are potentially viable ECIP projects. In some cases, the projects identified are larger than typical ECIP-funded projects. Smaller projects may not be cost effective due to increased $/kW costs associated with reduced economies of scale.

Photovoltaics

Site	Cost-Effective Size	Capital Cost ($)	Annual Utility Savings ($/yr)	Savings-to-Investment Ratio	Simple Payback (years)
Corpus Christi Army Depot	2.5 MW	$5,540,000	$404,910	1.12	17
Fort Devens	1.4 MW	$3,480,000	$181,830	1.16	11
Fort Hamilton	0.2 MW	$412,000	$34,290	1.24	14.7
Fort Irwin	15.8 MW	$28,900,000	$2,579,500	1.31	13.8
Fort Meade	20.3 MW	$36,700,000	$2,509,760	1.29	8.5
Natick Soldiers Systems Center	1.3 MW	$3,340,000	$204,860	1.28	10.6
Presidio of Monterey	7.6 MW	$14,400,000	$1,319,590	1.36	13.3
Fort McNair	5 MW	$10,000,000	$549,900	1.72	4.1
Camp Zama Japan	18.7 MW	$34,000,000	$3,735,570	1.7	10.8
Okinawa	5.9 MW	$11,600,000	$1,159,980	1.54	11.9
USAG Ansbach	8.5 MW	$16,100,000	$1,317,370	1.21	15.3
USAG Baumholder	7 MW	$13,500,000	$952,280	1.01	18.4
USAG Grafenwohr	31.9 MW	$57,100,000	$4,652,960	1.19	15.6
USAG Hawaii	36.4 MW	$64,900,000	$13,297,860	3.38	5.3
USAG Heidelberg	9 MW	$16,900,000	$1,198,570	1	18.4
USAG Hohenfels	8.2 MW	$15,600,000	$1,318,520	1.25	14.7
USAG Kaiserslautern	28.5 MW	$51,200,000	$3,984,520	1.12	16.5
USAG Livorno	3.4 MW	$7,180,000	$556,650	1.15	16
USAG Schweinfurt	7.5 MW	$14,200,000	$1,078,230	1.1	16.8
USAG Stuttgart	23.8 MW	$42,900,000	$3,366,630	1.13	16.3
USAG Vicenza	11.5 MW	$21,400,000	$1,798,200	1.24	14.8
USAG Wiesbaden	22.1 MW	$40,000,000	$2,995,610	1.07	17.3
Fort Buchanan	10.3 MW	$13,200,000	$2,839,960	3.49	5.2

Solar Hot Water

Site	Cost-Effective Size	Capital Cost ($)	Annual Utility Savings ($/yr)	Savings-to-Investment Ratio	Simple Payback (years)
Dugway Proving Ground	56,100 ft^2	$6,280,000	$541,420	1.74	13.7
Fort A.P. Hill	3,700 ft^2	$414,000	$26,160	1.15	20.1
Fort Irwin	44,700 ft^2	$5,000,000	$278,290	1.04	9
Hawthorne Army Depot	29,000 ft^2	$3,250,000	$280,860	1.74	13.7
Milan AAP	5,210 ft^2	$584,000	$41,170	1.3	17.5
Sunny Point	370 ft^2	$41,600	$2,640	1.19	20
Tooele AD	5,710 ft^2	$639,000	$41,860	1.26	19.2
Yuma Proving Grounds	1,640 ft^2	$184,000	$15,490	1.75	14.1
Camp Zama Japan	80,600 ft^2	$9,030,000	$650,940	1.34	17
Okinawa	1,030 ft^2	$115,000	$7,560	1.34	19.1
USAG Ansbach	40,400 ft^2	$4,530,000	$378,620	1.6	14.2
USAG Bamberg	22,600 ft^2	$2,530,000	$147,180	1.05	22.4
USAG Baumholder	50,700 ft^2	$5,680,000	$516,910	1.76	12.9
USAG Daegu	43,400 ft^2	$4,860,000	$351,210	1.35	17
USAG Grafenwohr	113,000 ft^2	$12,700,000	$846,070	1.23	18.8
USAG Hawaii	76,300 ft^2	$8,550,000	$1,048,400	2.61	9.2
USAG Hohenfels	24,600 ft^2	$2,750,000	$175,670	1.18	19.8
USAG Humphreys	65,100 ft^2	$7,300,000	$488,790	1.24	18.7
USAG Kaiserslautern	79,600 ft^2	$8,920,000	$634,530	1.34	17.3
USAG Red Cloud	131,000 ft^2	$14,700,000	$959,680	1.19	19.3
USAG Schweinfurt	27,000 ft^2	$3,030,000	$211,850	1.31	17.7
USAG Stuttgart	49,700 ft^2	$5,570,000	$393,360	1.32	17.5
USAG Wiesbaden	66,300 ft^2	$7,430,000	$549,310	1.4	16.5
USAG Yongsan	110,000 ft^2	$12,300,000	$742,260	1.08	21.3
Vilseck	39,800 ft^2	$4,460,000	$294,830	1.22	19
Fort Buchanan	1,790 ft^2	$201,000	$18,630	1.91	12.6
Fort Greely	17,100 ft^2	$1,920,000	$106,020	1.07	23.9

Solar Ventilation Preheating

Site	Cost-Effective Size	Capital Cost ($)	Annual Utility Savings ($/yr)	Savings-to-Investment Ratio	Simple Payback (years)
Aberdeen Proving Ground	225,000 ft^2	$6,170,000	$317,740	1.06	19.4
Dugway Proving Ground	68,800 ft^2	$1,880,000	$473,420	3.68	4
Fort A.P. Hill	13,400 ft^2	$368,000	$38,660	1.85	9.5
Fort Devens	13,100 ft^2	$359,000	$20,860	1.08	17.2
Fort Hamilton	13,100 ft^2	$359,000	$23,990	1.26	15
Fort Irwin	14,000 ft^2	$384,000	$24,290	1.36	15.8
Fort Knox	37,500 ft^2	$1,020,000	$61,740	1.16	16.5
Fort McCoy	62,700 ft^2	$1,710,000	$99,450	1.17	17.2
Hawthorne Army Depot	47,600 ft^2	$1,300,000	$321,860	3.02	4
Letterkenny Army Depot	117,000 ft^2	$3,210,000	$209,030	1.2	15.4
Milan AAP	23,200 ft^2	$636,000	$64,070	1.79	9.9
Natick Soldiers Systems Center	910 ft^2	$24,900	$480	1.28	51.9
Redstone Arsenal	362,000 ft^2	$9,920,000	$647,320	1.23	15.3
Sunny Point	1,010 ft^2	$27,700	$2,440	1.69	11.4
Tooele AD	9,760 ft^2	$267,000	$46,260	2.83	5.8
White Sands Missile Range	23,900 ft^2	$656,000	$31,940	1.12	20.5
Yuma Proving Grounds	1,400 ft^2	$38,600	$2,210	1.44	17.5

Biomass

Site	Cost-Effective Size	Capital Cost w/Incentives ($)	Annual Utility Savings ($/yr)	Savings-to-Investment Ratio	Simple Payback (years)
Redstone Arsenal	18.8 MW	$79,100,000	$15,500,000	1.15	9.1
USAG Hawaii	32.9 MW	$108,000,000	$44,640,000	4.95	3.8

Wind

Site	Cost-Effective Size	Capital Cost ($)	Annual Utility Savings ($/yr)	Savings-to-Investment Ratio	Simple Payback (years)
Corpus Christi Army Depot	1.5 MW	$3,620,000	$432,910	1.99	9.5
Fort Hamilton	1.5 MW	$2,750,000	$375,890	2.1	8.5
Fort Hood	27.6 MW	$58,900,000	$4,189,560	1.04	18.3
Fort Irwin	12.6 MW	$25,800,000	$2,869,500	1.7	10.6
Fort Leavenworth	5.8 MW	$13,800,000	$1,249,830	1.41	13.2
Fort McCoy	4.3 MW	$10,400,000	$767,340	1.11	16.9
Fort Meade	14.1 MW	$30,900,000	$2,579,760	1.28	14.8
Fort Riley	22.6 MW	$48,500,000	$4,919,200	1.58	11.7
Lake City AAP	11.1 MW	$24,600,000	$1,989,160	1.21	15.4
Lima Army Tank Plant	4.3 MW	$10,400,000	$898,470	1.33	13.9
Natick Soldiers Systems Center	1.5 MW	$3,520,000	$258,860	1.05	17.1
Presidio of Monterey	3.1 MW	$5,580,000	$745,590	2.06	8.8
Tobyhanna AD	3.7 MW	$8,850,000	$669,480	1.09	16.3
Military Ocean TML Concord	1.5 MW	$2,640,000	$208,000	1.07	17
Camp Zama Japan	7.6 MW	$17,500,000	$4,455,570	4.37	4.2
Okinawa	4.4 MW	$10,700,000	$2,509,980	4.02	4.5
USAG Ansbach	7.4 MW	$17,100,000	$3,357,370	3.32	5.5
USAG Bamberg	6.3 MW	$14,800,000	$2,088,660	2.32	7.9
USAG Baumholder	5.7 MW	$13,600,000	$2,786,280	3.49	5.3
USAG Benelux	3.7 MW	$9,030,000	$1,439,530	2.66	6.9
USAG Daegu	5.1 MW	$12,200,000	$1,368,300	1.81	10.2
USAG Grafenwohr	39.3 MW	$80,700,000	$12,492,960	2.52	7.3
USAG Hawaii	4.6 MW	$11,000,000	$4,747,860	10.52	1.6
USAG Heidelberg	5 MW	$12,100,000	$1,928,570	2.66	6.9
USAG Hohenfels	10 MW	$22,300,000	$3,488,520	2.57	7.1
USAG Kaiserslautern	24.4 MW	$52,300,000	$10,594,520	3.43	5.4
USAG Livorno	4.6 MW	$11,000,000	$1,639,650	2.45	7.4
USAG Red Cloud	13.2 MW	$29,100,000	$2,334,670	1.19	15.5
USAG Schinnen	0.9 MW	$2,170,000	$229,920	1.68	10.9
USAG Schweinfurt	8.7 MW	$19,700,000	$2,928,230	2.44	7.5
USAG Stuttgart	8 MW	$18,300,000	$3,076,630	2.81	6.5

USAG Wiesbaden	7.9 MW	$18,000,000	$2,765,610	2.54	7.2
Vilseck	7.4 MW	$17,000,000	$2,287,540	2.19	8.4
Fort Buchanan	6.2 MW	$8,610,000	$3,089,960	6.11	3
Fort Greely	10.1 MW	$22,700,000	$2,948,240	1.91	8.8

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NREL/BR-7A40-62947 • June 2015

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