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Clean Energy Technology Applications on US Mine Land: Technical Analysis

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CLEAN ENERGY TECHNOLOGY APPLICATIONS ON US MINE LAND: TECHNICAL ANALYSIS

Eve Tsybina, Ben Ollis, Femi Omitaomu, Emilio Piesciorovsky, Yarom Polsky, Scott DeNeale,
Archana Ghodeswar, Yan Liu, Edgar Lara-Curzio (Oak Ridge National Laboratory)

Patrick Dobson, Hanna Breunig, Curt Oldenburg, Erika Gasperikova, Sharon Borglin, Margaret Taylor,
Preston Jordan, Tim Kneafsey, Yingqi Zhang
(Lawrence Berkeley National Laboratory)

Gail Mosey, Wendy Hawthorne, Andrew Walker, Michael Ingram
(National Renewable Energy Laboratory)

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Prepared by
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, TN 37831
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ABBREVIATIONS

AC	alternating current
A-CAES	adiabatic compressed air energy storage
AMD	acid mine drainage
AML	abandoned mine land
AR	advanced reactor
BLM	US Bureau of Land Management
BLS	US Bureau of Labor Statistics
CAES	compressed air energy storage
CCUS	carbon capture, utilization, and sequestration
CDR	carbon dioxide removal
CPP	coal power plant
DAC	direct air capture
DC	direct current
DER	distributed energy resource
DOE	US Department of Energy
EGS	enhanced geothermal system
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
EPRI	Electric Power Research Institute
EW	enhanced weathering
EPZ	emergency planning zone
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GHP	geothermal heat pump
GIS	geographic information system
GSHP	ground source heat pump
IBDG	inverter-based distributed generator
IEA	International Energy Agency
LCOE	levelized cost of energy
LWR	light water reactor
MSHA	US Mine Safety and Health Administration
MWG	mine water geothermal
NEPA	National Environmental Policy Act of 1969
NG	natural gas
NOAA	US National Oceanic and Atmospheric Administration
NPP	nuclear power plant
NPV	net present value
NRC	US Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory

O&M	operations and maintenance
ORNL	Oak Ridge National Laboratory
PPA	power purchase agreement
PSH	pumped storage hydropower
PV	photovoltaic(s)
REC	renewable energy credit
REE	rare earth element
RG	Regulatory Guide
RPP	renewable power plant
SEL	Schweitzer Engineering Laboratories
SMR	small modular reactor
TVA	Tennessee Valley Authority
USGS	US Geological Survey

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EXECUTIVE SUMMARY

As the United States transitions toward a clean energy economy, an opportunity exists for redeveloping the more than 17,000 mine land sites located across the nation with clean energy technologies, which have a combined potential for generating more than 85 GW of clean electricity.

This report provides an overview of the potential of demonstrating and deploying clean energy projects on current and former mine land. *Clean energy project* refers to a project that demonstrates one or more of the following technologies: solar; microgrids; geothermal; direct air capture; fossil-fueled electricity generation with carbon capture, utilization, and sequestration; energy storage, including pumped storage hydropower and compressed air energy storage; and advanced nuclear technologies. The report discusses the following technologies and their potential for creating jobs and generating tax revenue that would result in direct and indirect benefits to the local economy.

- Solar photovoltaics (PV) is being developed on current and former mine land in various parts of the world, including the United States. This approach is attractive because it requires limited infrastructure investment and would utilize the bare surfaces of mines and tailing ponds. Solar resource availability may be greater in the southern regions, including the Interior and Appalachian Basins and the southwestern United States. However, since some mine land sites include areas of significant change in elevation, the deployment of PV on mine land may require sophisticated planning to account for shading and irradiance, or may require regrading of the areas. PV does not create significant environmental risks and generally does not face public resistance.

- Geothermal systems are often spatially and genetically associated with ore deposits, and in some cases, they have been discovered while in search for epithermal mineral resources. Numerous diverse geothermal applications have been employed at mine land around the world, including power generation, mineral extraction from geothermal brines, process heating, direct use for other mining operations, and direct use for non-mining operations and subsurface energy storage, including geothermal heat pumps. Case studies highlighting these applications provide key lessons relating to identifying drivers and barriers to geothermal resource deployment and can be used to create screening tools for identifying the types and locations of mine land most amenable to utilizing geothermal resources.

- Carbon capture, utilization, and sequestration technologies include direct air capture (DAC) and enhanced weathering. DAC technologies include air contactors, regeneration systems, and CO_2 compression systems. Captured CO_2 can be converted to valuable feedstocks or possibly injected into abandoned subsurface mines where it would be absorbed by alkaline rock waste and mine tailings or by the porous minerals along the walls of the mine. DAC systems can be coupled with energy sources such as wind, solar, grid, or geothermal. Many DAC systems require a source of water or steam; however, some are expected to be net producers of water. Local impacts of DAC systems are expected to be low, and are related to land footprint, material disposal, and upstream impacts of energy and material production.

- Compressed air energy storage is an established energy storage technology in salt caverns. It has the potential for implementation in underground mines by pressurizing and storing a large amount of air using electrical compressors when excess electricity is available. When a need for discharge emerges, the air is used to spin turbines and produce the necessary volume of electricity. Abandoned or unused mine openings, including shafts, adits, access tunnels, and mined workings of any orientation, offer potential for vast amounts of compressed air energy storage if the site characteristics meet operational requirements.

- Pumped hydropower storage can be implemented in surface and subsurface mines. In surface mine applications, both reservoirs may be located in a mine pit or artificial reservoirs made of excavated materials. In subsurface mines, the lower reservoir may be implemented by waterproofing and flooding mine shafts and tunnels. The water is then pumped from the lower reservoir to the upper reservoir during periods of low load and high production, and it is discharged through the turbines during periods of peak demand. The potential environmental damages associated with acidity of mine water or the presence of toxic chemicals incentivizes the development of closed-loop technologies, in which water circulates inside the pumped hydropower facility without being discharged into the external water basins.

- Advanced nuclear energy technologies include small modular reactors, which can be deployed locally to produce electricity and heat. Such units require seismic stability and a supply of cooling water, but population constraints may exist in some areas. Therefore, remote mine land could represent an optimal location for siting advanced nuclear energy technologies.

1. INTRODUCTION

1.1 SCOPE

As the United States transitions toward a clean energy economy, an opportunity exists for redeveloping the more than 17,000 mine land sites located across the nation with clean energy technologies, which have a combined potential for generating more than 85 GW of clean electricity. To further assess this opportunity, the Oak Ridge National Laboratory (ORNL), Lawrence Berkeley National Laboratory, and the National Renewable Energy Laboratory (NREL) were tasked with collecting relevant data sets and to conduct a technical review of the opportunities and challenges for the deployment of clean energy technologies on current and former mine land.

This report summarizes the results from these activities, including a review of relevant clean energy technologies, an overview of methodologies for site characterization, and an overview of methodologies for estimating technical and commercial potential. For the purposes of this report, *clean energy technologies* refer to solar, microgrids, geothermal, direct air capture (DAC), fossil-fueled electricity generation with carbon capture, utilization, and sequestration (CCUS), energy storage (including batteries, pumped storage hydropower [PSH], compressed air energy storage [CAES]), and advanced nuclear technologies, especially small modular reactors (SMRs).

The following sections provide a brief overview of current and former mine land in the United States, clean energy technologies that could be deployed on mine land, and existing tools and data sets to assess the potential of deploying clean energy technologies on current and former mine land. A more detailed analysis of these topics is presented in subsequent sections of this report.

1.2 OVERVIEW OF US MINE LAND

The abandoned mine sites are listed in the US Department of the Interior e-AMLIS (Enhanced Abandoned Mine Land Inventory System)[1] database (Figure 1-1), along with the locations of inactive metal mining operations in the United States obtained from the US Geological Survey (USGS) Mineral Resources Data System, which includes 64,883 sites identified as past producers. The US Forest Service (Shields et al. 1995) produced a comprehensive report delineating abandoned and inactive mines on US Forest Service lands, identifying the mines by commodity and mine type (placer, surface, or underground). The report used data from the Minerals Availability System/Mineral Industry Location system database that was operated by the now-defunct US Bureau of Mines, which recorded more than 200,000 mineral locations in the United States, with more than 89,000 being characterized as past producing locations. Surface mines prevail in the United States, with only 174 operational underground mines as of 2021 (NMA 2022b).

[1] https://amlis.osmre.gov/Map.aspx

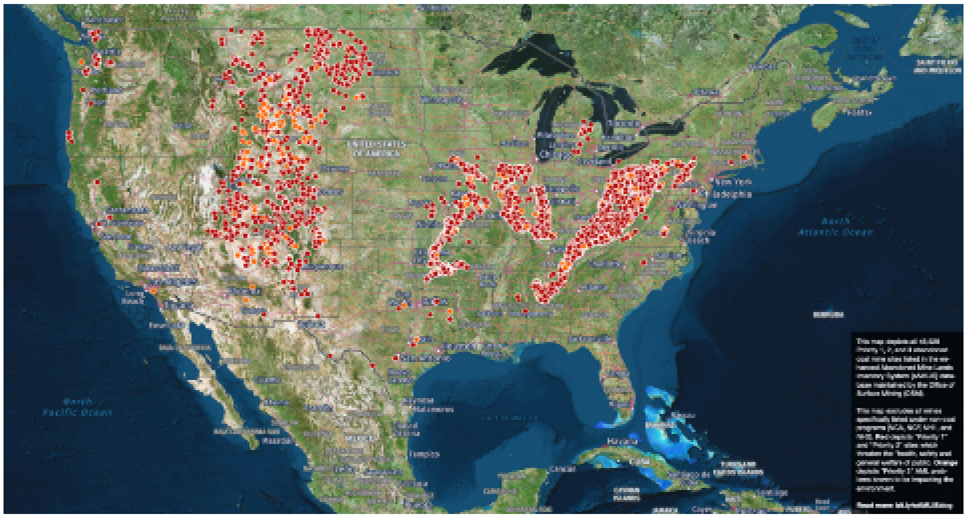


Figure 1-1. Locations of abandoned coal mine sites listed in the e-AMLIS database.[2]

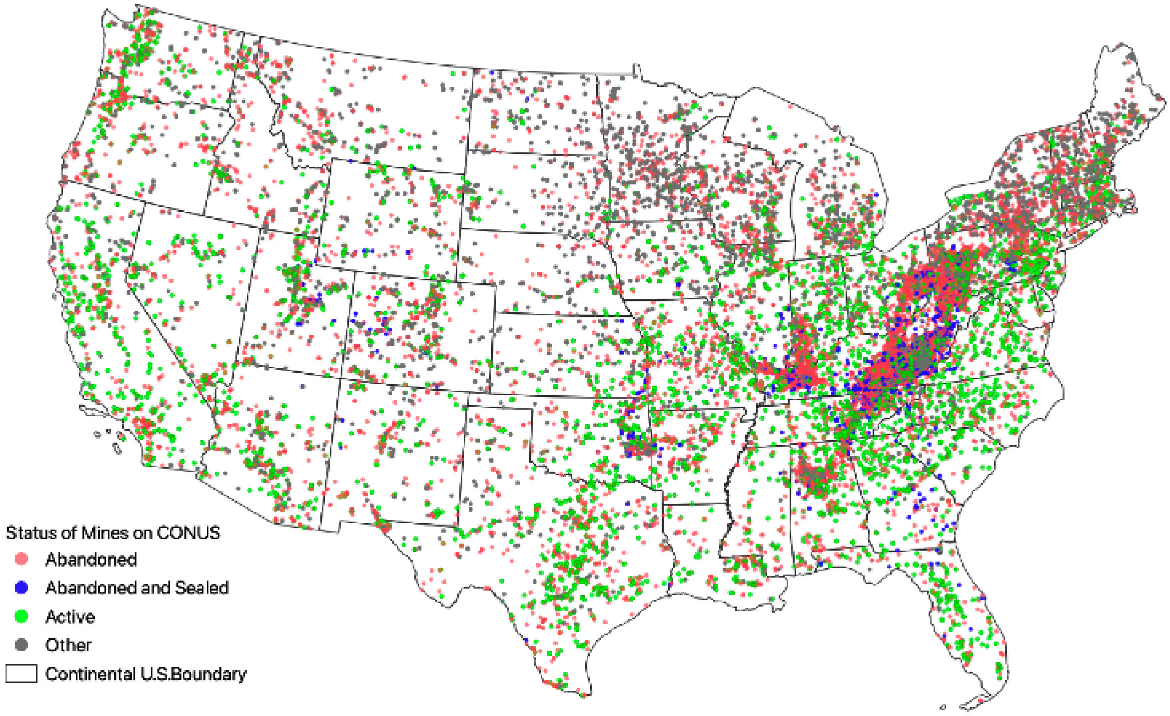
1.2.1 Coal Mine Land

The coal mining industry employs more than 60,000 people (NMA 2022b), and about 80% of coal mines are in the eastern United States, including Alabama, Georgia, Kentucky, Tennessee, Virginia, West Virginia, Pennsylvania, and Maryland. Large coal mines also exist in Wyoming, Utah, and Colorado, which—despite accounting for only 8% of the number of active mines—produce about 60% of the total coal output in the United States (EIA 2021).

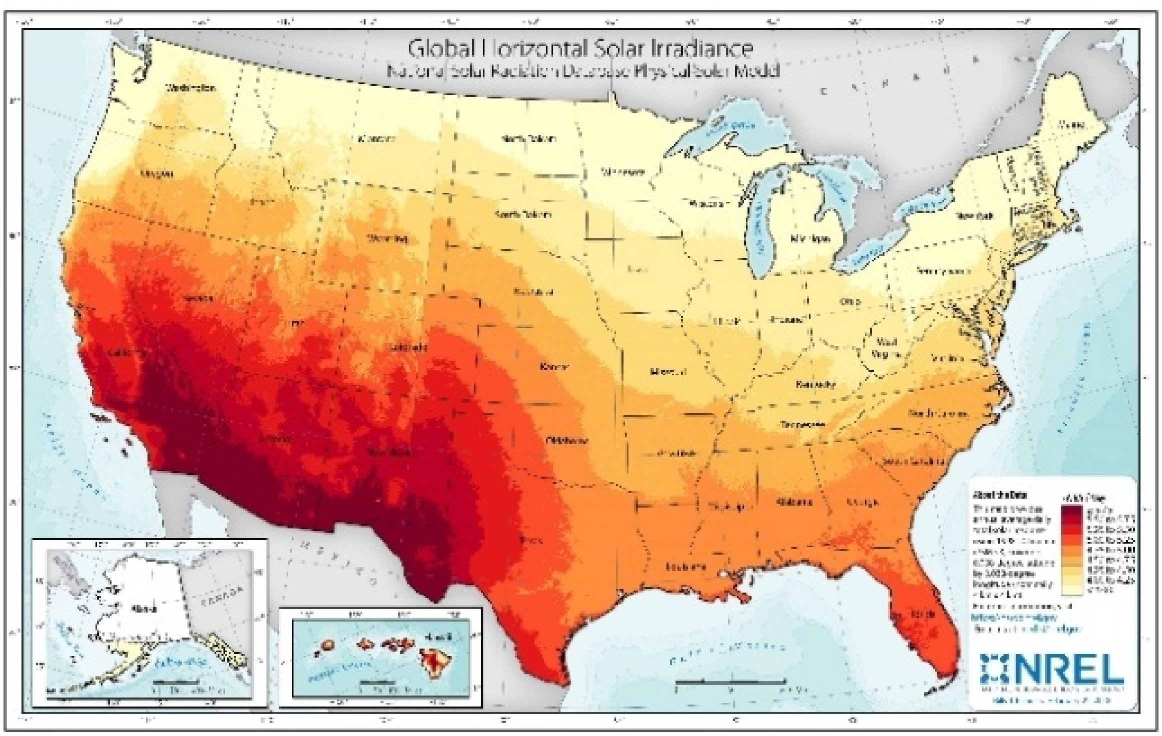
The US coal mine reclamation bond release was around 40,000 acres per year until 2020 and increased to about 50,000 acres after that (NMA 2022c), indicating a large potential for the use of former coal mine land. Coal mine land sites have a significant overlap with some of the areas in the United States that have a substantial resource potential for clean energy development. Specifically, mine land sites are in areas with high extent of solar irradiance, as shown in Figure 1-2(b). An overlap exists between coal mine land and high-temperature geothermal energy resources, mainly in the western states such as Utah, Nevada, Oregon, as shown in Figure 1-2(c). Low-temperature geothermal resources are present in the mining areas in Montana, North Dakota, Minnesota, Nevada, and Utah, as shown in Figure 1-2(d). Mine land also presents an opportunity for siting modular nuclear power plants (NPPs), which are often located far from population centers, as indicated in Figure 1-2(e).

[2] https://skytruth-org.carto.com/viz/743a74d4-6e94-11e5-9f65-0ecfd53eb7d3/public_map

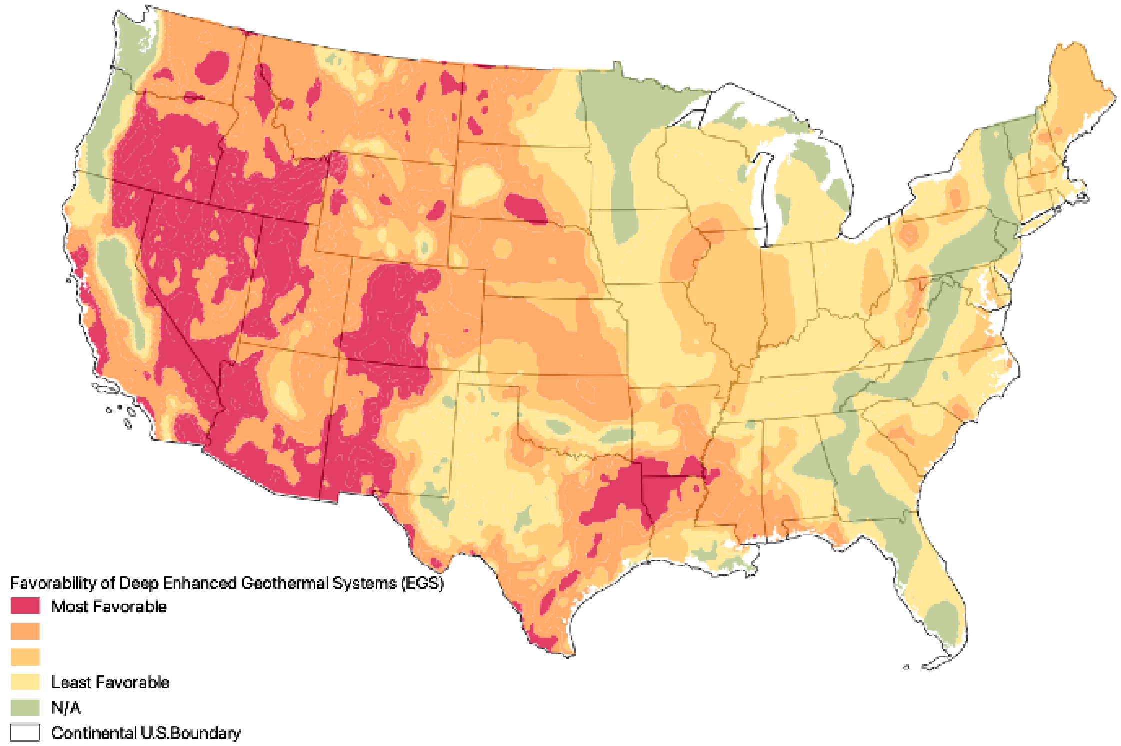
a


Status of Mines on CONUS
Abandoned
Abandoned and Sealed
Active
Other
Continental U.S.Boundary

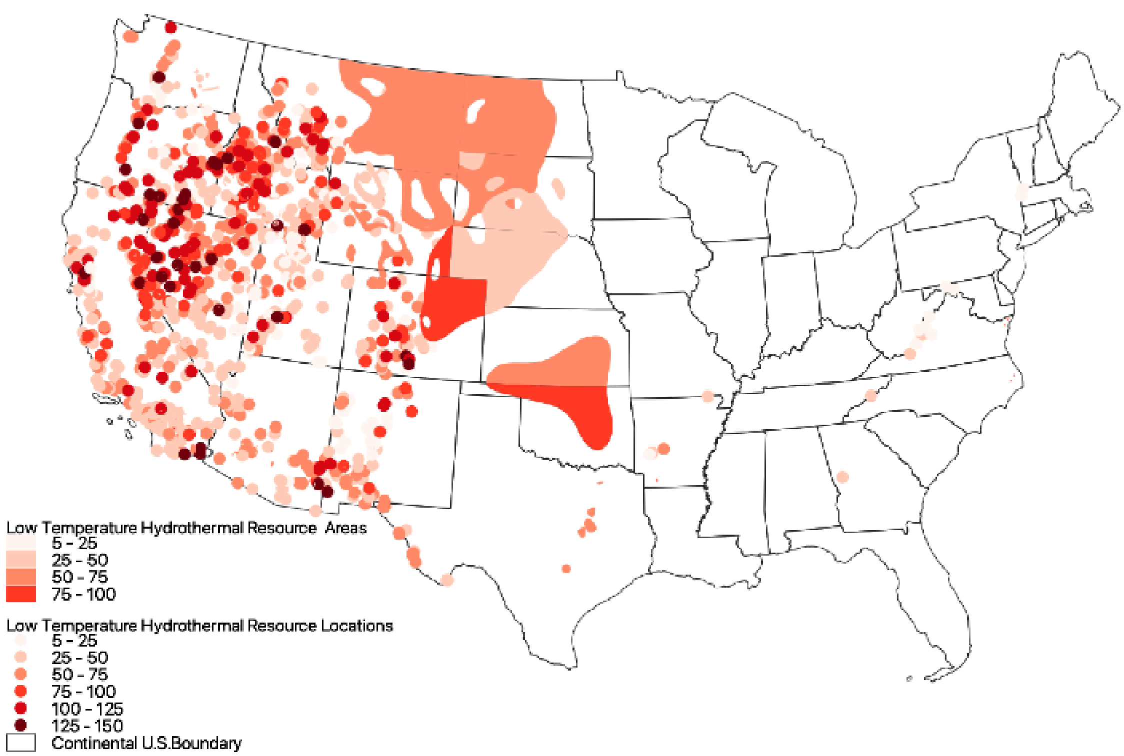
b


Global Horizontal Solar Irradiance
NREL

c


Favorability of Deep Enhanced Geothermal Systems (EGS)
Most Favorable
Least Favorable
N/A
Continental U.S.Boundary

d


Low Temperature Hydrothermal Resource Areas
5 - 25
25 - 50
50 - 75
75 - 100
Low Temperature Hydrothermal Resource Locations
5 - 25
25 - 50
50 - 75
75 - 100
100 - 125
125 - 150
Continental U.S.Boundary

e

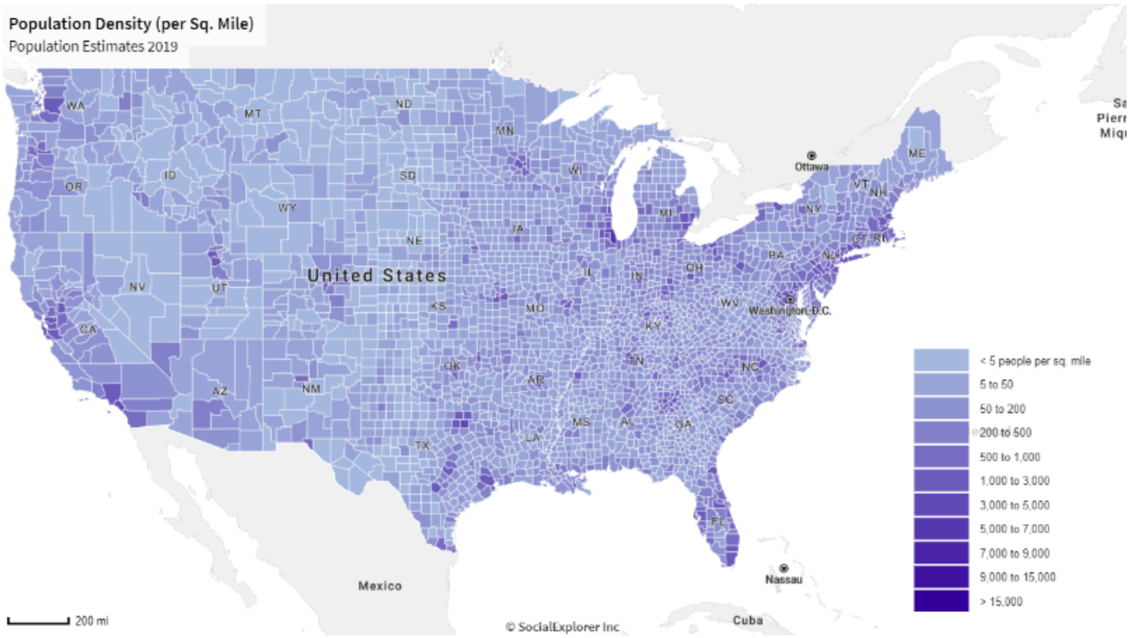


Figure 1-2. Locations of operational and nonoperational mines and resource potential for clean technologies.[3]

1.2.2 Hard Rock Mine Land

The Mining Law of 1872, as currently amended, governs mining claims of "locatable minerals" on public land. According to the US Bureau of Land Management (BLM), "Locatable minerals include both metallic minerals (gold, silver, lead, copper, zinc, nickel, etc.) and nonmetallic minerals (fluorspar, mica, certain limestones and gypsum, tantalum, heavy minerals in placer form, and gemstones)."[4] According to the Federal Record, hard rock minerals "include base metals, precious metals, industrial minerals, and precious or semi-precious gemstones. Hard rock minerals do not include coal, oil shale, phosphate, sodium, potassium, or gilsonite deposits. Also, hard rock minerals do not include commodities the government sells such as common varieties of sand, gravel, stone, pumice or cinder."[5] Other locatable minerals include Pt, Mg, tungsten, bentonite, barite, feldspar, and uranium (National Research Council 1999). An overview of the inactive metal mines is provided in Figure 1-3.

[3] https://www.nrel.gov/gis/solar-resource-maps.html, https://gdr.openei.org/submissions/842, https://www.socialexplorer.com/d92c7c1274/view, https://onemap.cdc.gov/portal/apps/sites/#/eji-explorer
[4] https://www.blm.gov/programs/energy-and-minerals/mining-and-minerals/about
[5] https://www.ecfr.gov/current/title-43/subtitle-B/chapter-II/subchapter-C/part-3500/subpart-3501/section-3501.5

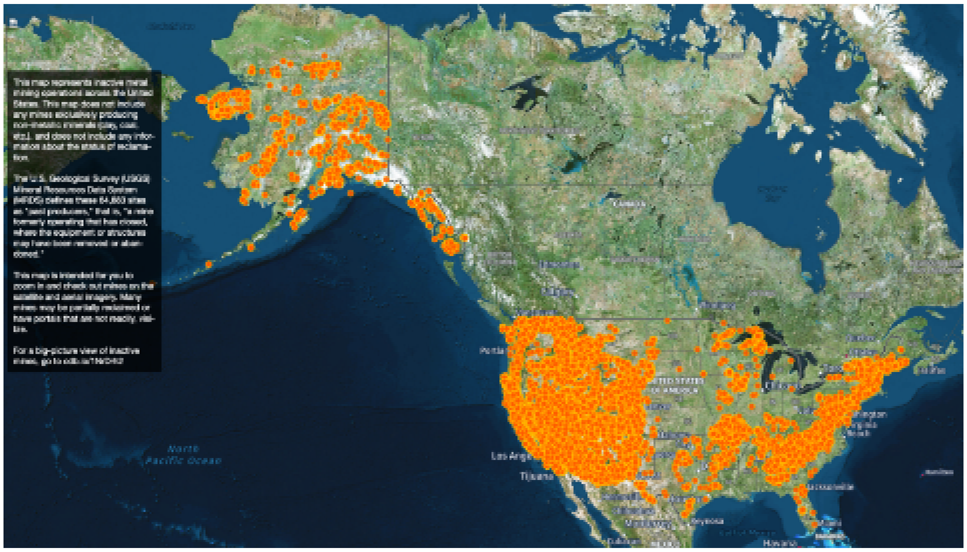


Figure 1-3. Map of inactive metal mining operations in the United States using data from the USGS Mineral Resources Data System.[6]

The United States has a large inventory of active hard rock mines and an even larger number of abandoned and inactive hard rock mines. According to the Congressional Research Service (Humphries 2009), most current mining activities and mineral claims under the Mining Law of 1872 are in Nevada, Arizona, California, Montana, and Wyoming. As of FY 2005, there were 207,241 active mineral claims in the United States,[7] but only a fraction of these correspond to active working mines. Several federal and state databases provide information on these mines (e.g., mine type, minerals mined, mine operation status, location). Appendix A lists some of these databases. BLM estimated that in 2017, there were 52,200 known abandoned mine land (AML) sites on public land.[8]

1.3 OVERVIEW OF APPLICATIONS AND TECHNOLOGIES UNDER CONSIDERATION

Depending on available land and type of mine land, several standalone clean energy technologies could be deployed on current and former mine land. For example, surface mines such as open pit or hilltop could be used for solar, pumped hydropower, carbon capture, or nuclear energy. Subsurface mines could be used for carbon capture, compressed air, geothermal energy production, or PSH. Active mines could be used for installing smaller scale generation such as photovoltaics (PV) combined with batteries, or nuclear energy.

Solar PV is currently deployed on several current and former mine land in the United States. The solar resource availability tends to be greater in the southern regions, including the Interior and Appalachian basins and the southwestern United States. In some instances, PV does not require extensive investment in infrastructure or reclamation. However, on mine land with changes in elevation, the deployment of PV may require sophisticated planning to account for shading and irradiance or may require regrading of the areas. PV does not create significant environmental risks and generally is not associated with public resistance, but installations of PV would have to be complemented with deployment of energy storage resources, such as batteries.

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[6] https://skytruth-org.carto.com/viz/8e8d33f1-9a26-442a-93be-365df5c94190/public_map
[7] https://www.everycrsreport.com/files/20090717_RL33908_fb14efa02d3717742b1e1ba990aad057695a491b.html
[8] https://www.blm.gov/programs/public-safety-and-fire/abandoned-mine-lands/blm-aml-inventory

CCUS technologies include the capture of CO_2 at point sources of CO_2 rich flue gas, such as coal- and natural gas (NG)–fired power plants, and its transportation to an end point, whether that be for utilization or sequestration. Utilization may entail the direct use of CO_2 or its conversion to valuable fuels and chemical feedstocks. Capture and utilization of CO_2 would be unlikely to occur directly on mine land unless a facility, such as a power plant, is present on site. More practically, CO_2 captured at a facility near mine land that overlays geologic sequestration formations will transport CO_2 for injection via pipelines or other alternative modes of transportation. In that case, CCUS is not expected to require much surface area or have a high energy or water footprint aside from the well pad and injection compression energy requirement.

Numerous processes for DAC are in various stages of commercialization, all essentially include an air contactor, a regeneration system, and a CO_2 compression system if pure CO_2 gas is generated. For technologies that involve mineralization, a solid by-product is produced instead of a gaseous CO_2 stream. Because the carbon efficiency of a DAC system depends on available low-carbon energy sources, DAC will have additional impacts and land footprint associated with the power system. Enhanced weathering (EW) is another method of mineralization that can be employed on mine land with alkaline rock waste and mine tailings. This process leverages the reactivity of mine waste to capture CO_2 directly from ambient air or from a concentrated gas stream. The process may require substantial amounts of land for spreading materials and achieving meaningful reaction rates.

PSH is a proven energy storage technology that has been deployed at dozens of facilities in the United States and around the world. Although none have been deployed on current and former mine land, several applications have been made to develop such projects in the United States, and interest is growing internationally. PSH uses the elevation differential between two water bodies to enable pressurized water flow to mechanically spin a turbine-generator unit and produce electricity. Power is produced when water flows downhill, and a pump-motor system is used to refill the upper reservoir. PSH accounts for the vast majority of current energy storage capacity and generation in the United States and internationally.

NPP technologies under consideration include advanced reactors (ARs), such as SMRs, and light water reactors (LWRs). There is well-defined regulatory guidance for siting an NPP in the United States, including the regulations for nuclear plant siting in 10 CFR 100 and the regulatory guidance for siting an NPP in Regulatory Guide (RG) 4.7 by the US Nuclear Regulatory Commission (NRC; NRC 2014) and the 2002 Electric Power Research Institute (EPRI) Siting Guide (Omitaomu et al. 2012). Some of the existing guidance developed for large LWRs may be less applicable to AR designs. The available guiding concepts have been used to develop exclusionary, avoidance, and suitability criteria for screening sites for a variety of power generation types, including NPPs. For a given technology application, evaluation parameters must be developed that encompass several key screening criteria that essentially provide for a basic site characterization for that application.

CAES is an established energy storage technology in salt caverns with potential for implementation in underground mines. A CAES system stores energy by pressurizing and storing a large amount of air using electrical compressors when excess electricity is available (e.g., during off-peak hours). The stored energy is converted to electricity and delivered back to the grid by turbines when electricity demand increases. Abandoned or unused mine openings, including shafts, adits, access tunnels, and mined workings of any orientation, offer potential for vast amounts of CAES if the site characteristics meet operational requirements (Section 3.3).

Geothermal energy is the heat contained within the earth, and its distribution varies as a function of depth and heat flow. This thermal energy can be “mined” from the subsurface by circulating fluids through hot rocks and bringing those fluids back to the surface. Depending on the temperature of the resource, geothermal energy can be used for a variety of applications, including electrical power generation (generally for resources ≥130°C) and direct use applications such as heating and drying. The shallow (<200 m) subsurface can also be used to power geothermal heat pumps (GHPs), which can be used for heating and cooling. Geothermal fluids contain dissolved mineral constituents, which may also have economic value. The subsurface also provides the opportunity to store and retrieve thermal energy as needed, serving as a natural geo-battery. In the context of mine land, abandoned mines are often flooded, and the water in the subsurface excavations could potentially be harnessed for heating and cooling, and be used as a thermal storage reservoir. In some cases, mines may be located in areas with high heat flow, making higher-temperature applications viable.

1.4 RELEVANT TOOLS AND DATA SETS

The potential of deploying individual, or combinations of technologies, on mine land can be assessed using some of existing tools and databases.

The tool set/database file summarized in the Supplementary Material contains two sheets. On the first sheet, the table lists the format of the Task 2 Data for the Office of Clean Energy Demonstrations Clean Energy on Mine Land spreadsheet, which compiles collected data sources, models, and tools as they relate to clean energy on mine land. The entries in the spreadsheet represent relevant public data sets from federal and state agencies, universities, national laboratories, private organizations, and other relevant institutions. This list summarizes data sets that include data for coal and hard rock mining, as well as assessment tools that can be used to analyze clean energy projects on mine land.

The primary classifications for the sources include overall assessment tools, as well as national or state inventories of data. The name of the data set and responsible organization or state are identified, along with a description and web page link to the listed source and indication of whether the source is publicly accessible. The sources are also classified to show whether the focus is specific to mine land, what specific technologies are included, and whether the source provides information to assist in overall planning, geographic information system (GIS) mapping, economic impact assessment, or energy equity and energy justice goals.

The second sheet is specific to the tool OR-SAGE (Oak Ridge Siting Analysis for Power Generation Expansion). It includes the name and parameters of each of the data layers, as well as the source and data acquisition time. OR-SAGE (Omitaomu et al. 2022) is a GIS-based multicriteria decision analysis tool developed by ORNL to inform owners, vendors, policymakers, regulators, and other stakeholders about nuclear fuel cycle siting issues, site availability, capacity availability, fuel cycle optimization, transport optimization, coal-fired plant backfits, support of federal energy goals, evaluation of policy issues, and other matters. OR-SAGE is designed to use industry-accepted practices for screening sites and then employ the proper array of data sources through considerable GIS and computational capabilities available at ORNL. Initially, ORNL staff adapted and extended the 2002 EPRI Siting Guide (Omitaomu et al. 2012) methodology, which had been developed for the purpose of screening potential sites at national and regional scales during early site permit applications. The tool provides high-resolution analysis insights and, thus, can focus specifically on user sites of interest. This is made possible by dividing the contiguous United States into 100 × 100 m (1 hectare) squares (cells) and applying successive suitability criteria to each cell. If a cell meets the user-specified query values for each criterion, then the individual cell is deemed a candidate area for siting a power plant. In this manner, a collection of cells that make up a site of a given size can be evaluated.

The OR-SAGE process is to evaluate site-screening criteria for large and small NPPs, advanced coal plants with carbon capture and sequestration, wet and dry solar power technologies (excluding PV cells), CAES, nuclear fuel cycle component siting, spent nuclear fuel storage siting, and borehole waste storage siting. Principal differences between various NPP technologies are population density calculations, cooling water demand, and plant footprint.

Essentially, OR-SAGE is a visual, relational database. The database partitions the contiguous United States, a total of 7.2E8 hectares (approximately 1.8 billion acres), into 100 × 100 m (1 hectare or approximately 2.5 acres) cells[9]. The size used for the analysis is selected to accommodate the approximate smallest footprint required for AR technologies and to provide adequate discrimination of spatial extent for the criteria. Therefore, siting analysis on this database computes on approximately 700 million individual land cells. More than 50 data sets of various geospatial resolutions and formats are integrated in OR-SAGE to build the parameter layers and populate each cell. Data sets that provide national or greater coverage with attributes matching the desired site evaluation parameters are selected. The specific parameters are identified for each power source. Appropriate scaling and resolution of each data set must be considered before using a data set in the study. Figure 1-4 illustrates an overview of the OR-SAGE analysis processes.

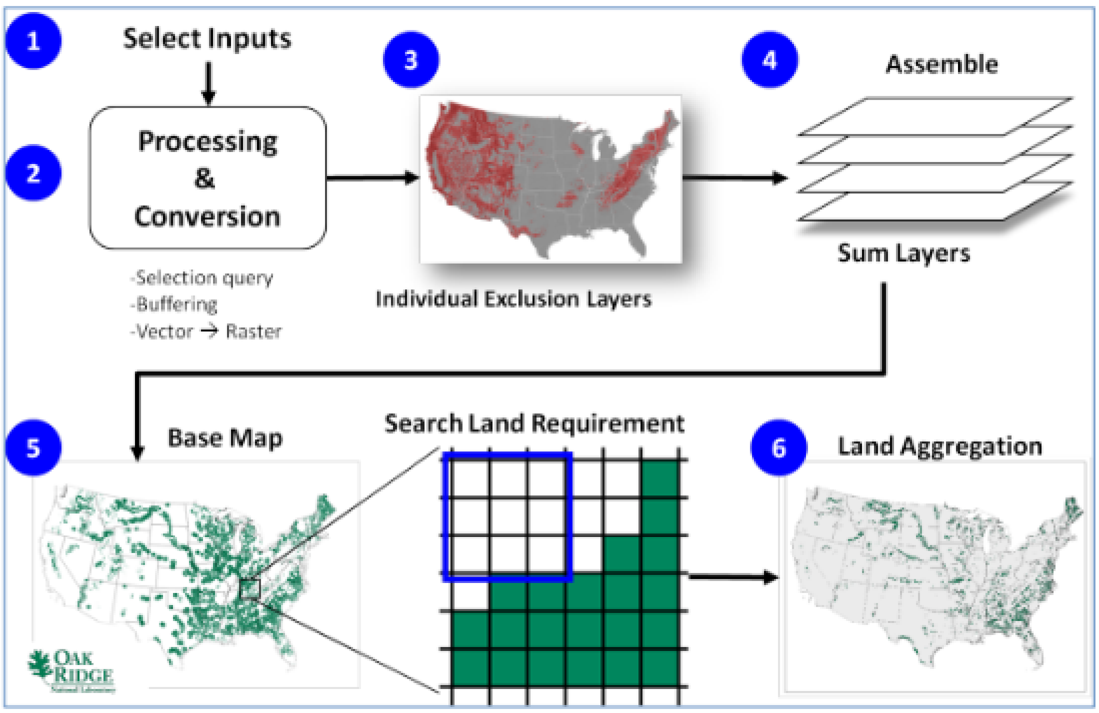


Figure 1-4. Overview of OR-SAGE analysis processes (Omitaomu et al. 2012).

The data set sources used in OR-SAGE include the following:

- US Energy Information Administration (EIA)
- USGS and state geological surveys
- US National Park Service
- US Forest Service

[9] https://www.energy.gov/ne/articles/expansion-or-sage-analysis-tool-cover-alaska

- US Fish and Wildlife Service
- US Department of Transportation
- Federal Emergency Management Agency
- Federal Aviation Administration
- US Census Bureau
- ORNL LandScanTM data (a high-resolution population distribution database developed by ORNL); the assumption here is that the population database directly accounts for the buildings located in the study areas.
- ORNL 7 day, 10 year low flow calculated data
- Many other commercial sources
- OR-SAGE to investigate benefits and challenges of converting retiring coal power plants (CPPs) into NPPs (Hansen et al. 2022): This work is an important reference because CPPs and coal mine land sites are highly correlated. In the study, approximately 50 potential siting criteria were identified in various sources related to health and safety, environment, socioeconomic, and engineering factors. The study team developed a subset of parameters for nuclear plant siting that were considered to have the most impact on the viability of any given site and were directly amenable to application of GIS techniques. The selected AR parameters are based on providing a high level of discrimination and readily available data from the US Department of Energy (DOE) and EIA.

The US Environmental Protection Agency (EPA) has developed a screening mapping tool (EPA 2019), the RE-Powering Mapper, to provide simple siting analysis for repowering contaminated lands, landfills, and current and former mine land as renewable energy solutions for critical infrastructure, such as wastewater treatment plants. It provides vulnerability screening (threats from natural hazards), proximity screening (proximity to critical infrastructure), economic screening (cost competitiveness of developing a renewable energy site vs. other electricity-generating technologies) and needs screening (generation potential vs. energy needs by critical infrastructure). This tool does not consider nuclear power. The tool analytics are suitable for coarse screening. In comparison, OR-SAGE is suitable for comprehensive siting analysis for repurposing mine land for NPPs.

A comprehensive tool for the repurposing of mine land is currently being developed through Energy & Extractives program at the World Bank. The tool evaluates land using the following criteria: location and redevelopment potential, geotechnical stability, topography and hydrography, environmental risks / liabilities, development potential and financial risks. The resulting classification assigns land to commercial or industrial use, agricultural development, energy projects, or recreational use. The tool is accessible in the pilot form in the United States.[10]

The following sections present a detailed review of studies on clean energy project deployment on mine land, followed by an overview of methodologies for site characterization and a discussion of limitations of clean energy technologies.

[10] https://lurademo.geosysta.com/

2. REVIEW OF CLEAN ENERGY PROJECT DEPLOYMENTS AND STUDIES FOR MINE LAND

With the move away from fossil fuels toward green energy resources, mining companies are looking for ways to incorporate renewable energy development into their business models. The Columbia Center on Sustainable Investment published an extensive study examining how renewable energy can be integrated into mining operations, including an example from a mine using geothermal energy (Maennling and Toledano 2018). Figure 2-1 is a schematic diagram from that report highlighting some of the challenges and drivers that can lead to the development of green energy projects associated with mining operations to lower the mine's carbon footprint and reduce operating costs.

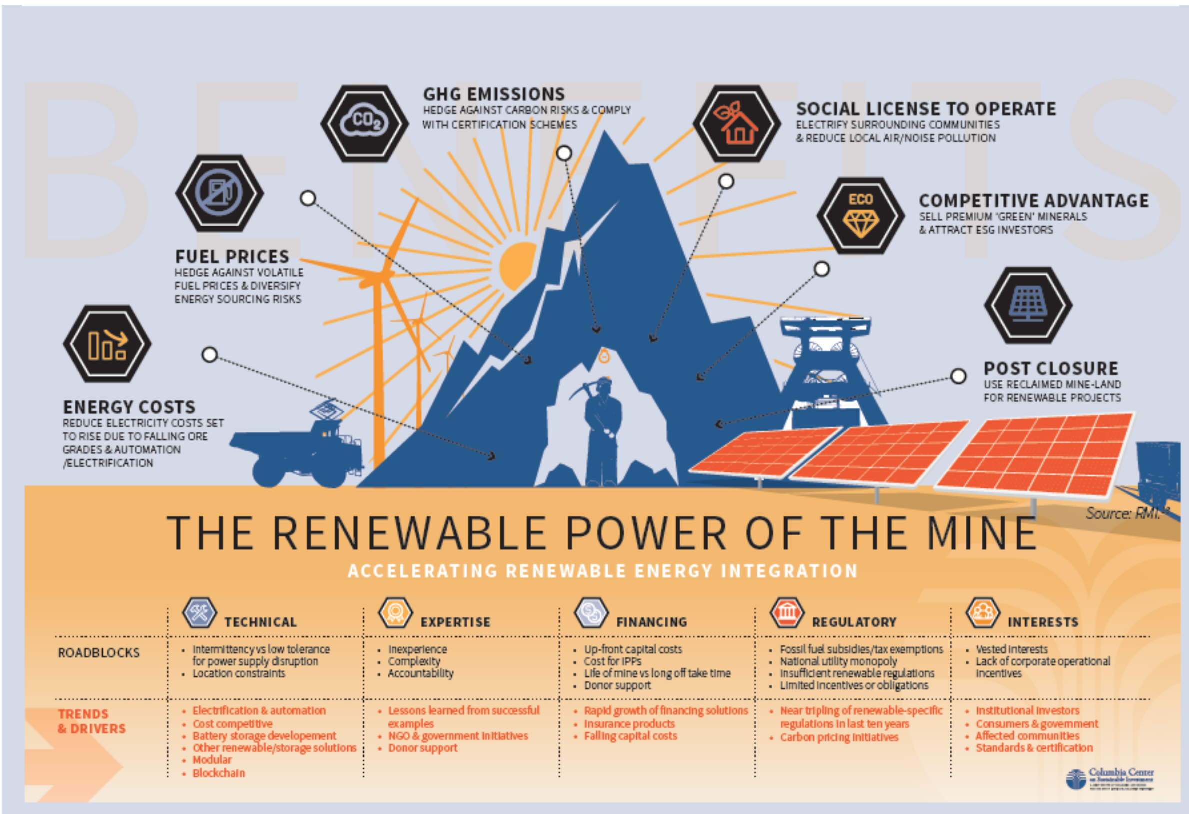


Figure 2-1. Schematic representation of benefits, obstacles, and drivers related to integrating renewable energy into mining operations (Maennling and Toledano 2018).

The Rocky Mountain Institute has conducted an extensive review of renewable energy projects that have been installed at current and former mine land around the world. The review was part of their Sunshine for Mines initiative (Kirk and Cannon 2020). As part of this effort, The Rocky Mountain Institute has developed a Renewable Resources at Mines tracker, which notes that as of 2019, renewable energy projects at 88 active and legacy mine sites had a global cumulative renewable energy capacity of almost 1.9 GW. Energy production consisted of wind, solar, and hybrid systems (Figure 2-2). However, this compilation did not include any geothermal projects at current and former mine land. This compilation also only included power generation projects and did not include direct uses of geothermal energy that would displace the need for other energy sources.

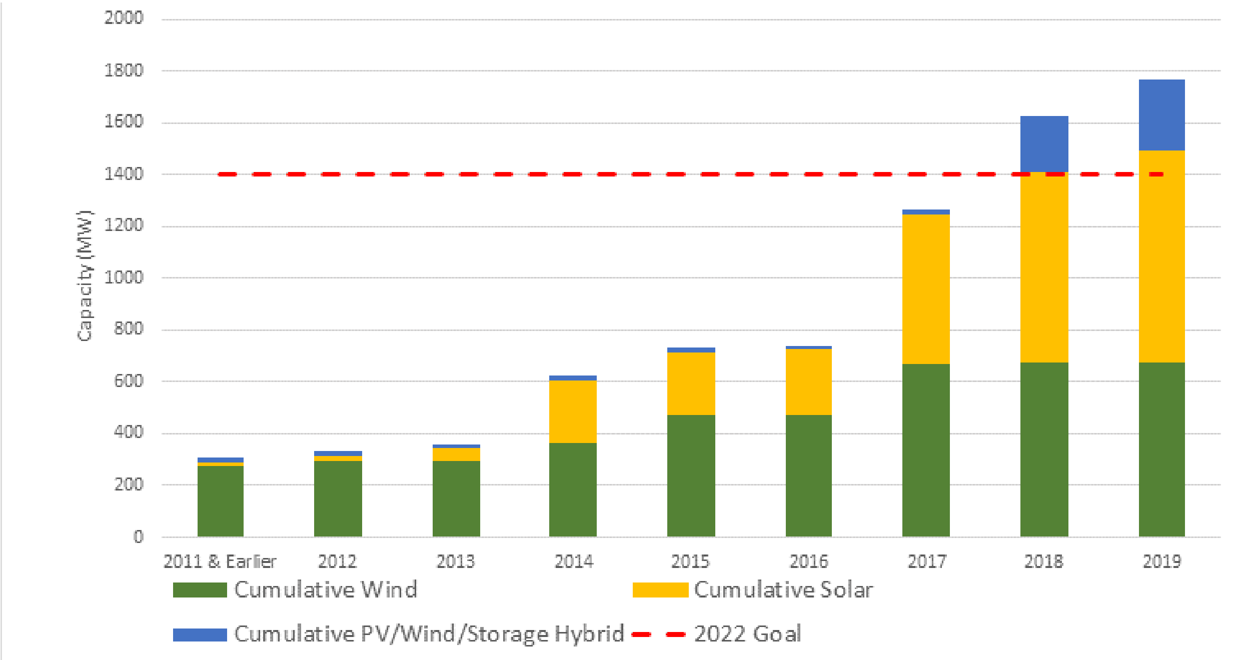


Figure 2-2. Cumulative commissioned renewable energy capacity (measured in megawatts) of projects associated with worldwide mining operations (Kirk and Cannon 2020).

2.1 SURFACE APPLICATION

2.1.1 Solar Power

PV modules are panels that convert sunlight directly into electricity using semiconductor materials such as silicon. Panels are wired in series to provide direct current (DC). An inverter converts this DC to alternating current (AC) at the desired voltage and configuration of phases to be compatible with utility power. PV systems often operate in parallel with utility power; however, they may operate in a standalone mode with batteries and grid-forming inverters. PV modules may be mounted on fixed racks or racks that track the sun throughout the day.

2.1.1.1 Technical challenges

Current and former mine land presents an opportunity for the development of solar PV power plants. The principle of installing PV on surface coal mines is illustrated in Figure 2-3.

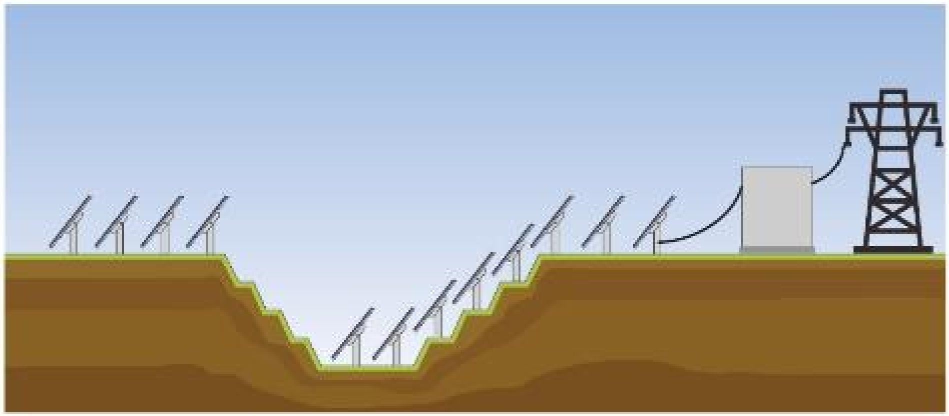


Figure 2-3. General principle of installing PV on mine land. For illustrative purposes only. Not to scale.

All available surfaces of a mine can be used to install solar PV systems. Ground-mounted systems can be installed around the pit, at the bottom, or on the walls. In the event of a flooded mine, floating systems can be installed on the surface of the lake.

The installation of PV systems on current and former mine land poses several technical challenges. Some of them, such as the choice of equipment, are the same as for regular PV systems. Some technical challenges are specific to mine land. Existing research suggests two main areas for PV that are specific to installation on mine land: irradiance and geotechnical conditions.

Irradiance and light barriers in the presence of land slope

The first factor to consider is irradiance. Global horizontal irradiance, diffuse horizontal irradiance, and direct normal irradiance are the three indicators typically used to represent irradiance in PV modeling literature. The amount of irradiance received by most of the US territory is sufficiently high for PV systems. The average global horizontal irradiance is between 3 and 6 kWh/m^2/day[11], with the PV capacity factors for most states between 15% and 30%[12]. While locating PV further south makes them more commercially preferrable, there is enough solar irradiance to operate PV in almost all states except for Alaska.

Irradiance is affected by tilt and azimuth, which implies that only part of the mine could be used for PV. In addition to regular irradiance criteria, the useful area on the open mine is affected by shade. Existing research has identified several sources of shade, including natural light barriers such as plants and the surrounding topography (Choi and Song 2016). Steepness affects the feasibility of installing PV. Part of the surface mine are its walls, and the existence of these walls affects the total used space. The recommended steepness for a surface coal mine, for instance, was found to be less than or equal to 30° (Bódis et al. 2019). Some estimates indicate that approximately 55% of total mine area can be used for PV installations (Pavloudakis et al. 2020). The most cost-effective approaches have evolved on flat land; therefore, grading may be required to level the profile. Installation on steeply sloped surfaces has been demonstrated, but at a higher cost because of the long spans of structural steel used between the places where foundations can be installed. Driven piles are the most common foundation type, and deployment of PV might be limited by lack of access by installing equipment. Removal of vegetation from around the

[11] https://nsrdb.nrel.gov/data-viewer
[12] https://www.eia.gov/todayinenergy/detail.php?id=39832

PV array might be complicated by limited access, steep slopes, or other complications specific to the mine site.

High Temperatures

A high air temperature can be induced by the heat retained by the mass of the open pit mine radiating between surfaces, and high air temperature reduces the operational efficiency of PV modules. Existing experimental evidence suggests that mine installations supporting lower ground temperature are preferred to those that result in higher ground temperature (Brooks et al. 2012).

Dusting and Cleaning

Another factor that can affect the effectiveness of PV modules is dust from the open bare surface of coal mines. Research suggests that dust can accumulate on PV modules in surface coal mines and reduce efficiency of production by 2%–6% (Nurjanah et al. 2021, NREL 2018). If there is no specific source of soiling, power producers rely on rain to keep PV modules sufficiently clean. In the presence of a continued source of dust, cleaning may increase operating costs. Cleaning costs have been reported to be approximately $25,000 per year for a 10 MW PV system[13].

Geotechnical conditions

The geotechnical and hydrological conditions may affect the placement of PV systems on mine land in numerous ways. Although these have not appropriately addressed in the research and industry literature, it may be helpful to include them here due to their relevance for mine projects.

First, there may be instances where the ground may not be penetrated by piles. This could happen in quarries or hard rock mines. Ballasted (weighted) racks could be used in such locations, but after careful consultation with regulators and possible re-design of landfill cap.

Further, soil type, such as sand, rock, or loam, would affect foundation selection and influence the shape of helical piles. Solid rock or rocky soils can preclude the use of driven piles and require more expensive foundation designs.

The existence of unstable soil may also be the case in mines. Such conditions may be found around tailing piles and tailing ponds. Such soils would be grained and not sufficiently compacted to provide stable support for PV systems. If underground mining took place under the PV site, this may create conditions for soil subsidence.

Finally, some mines may result in soil contamination or changes in soil acidity. This could potentially affect the driven piles of PV systems and create conditions for corrosion. Care must be taken also not to damage the contaminated soil design with the installation equipment.

Hydrological conditions and stormwater management

Surface mines are large areas exposed to precipitation, high runoff rates, and ground water flows. They accumulate lakes that may have to be drained. Water flows may erode soil and affect the support structures. Proper hydrological designs may be needed to account for groundwater flows. Stormwater management for PV systems could be integrated with the site-wide water runoff plans with measures to route flow and prevent erosion. Recently, inverters and other equipment have been mounted on poles or

[13] https://www.nrel.gov/docs/fy20osti/74840.pdf

elevated platforms to reduce exposure to flooding (Elsworth and Van Geet 2020). There are also suggestions for using floating PV arrays for surface mines that have already been flooded (Song and Choi 2016). Stormwater may also be stored on-site for operational uses.

Other considerations

Other considerations, such as the choice of generating equipment and infrastructure, are not specific to mine land. They are therefore not reviewed here. Some further literature includes the review of fixed or tracking systems (Nsengiyumva et al. 2018), selection of modules (Pandey et al. 2016), and concentrated solar technology (Ahmadi et al. 2018).

2.1.1.2 Financial characteristics

The main approach to estimating the financial feasibility of developing PV on current and former mine land is the net present value (NPV) (Choi and Sonog 2016). Although some researchers do direct NPV calculations, some refer to specialized software. The most popular tool is RETScreen[14] (Li 2021, Mathew 2017, Mardonova and Choi 2019), which was developed by Natural Resources Canada to determine the most commercially attractive locations for mine land. Besides financial payoff, it includes some technical and environmental considerations. System Advisor Model,[15] developed by NREL, is a common tool for simulating PV system energy generation based on orthogonal irradiance solar resources and details of component efficiency. REopt (Renewable Energy Optimization),[16] also developed by NREL, enables integrating solar with batteries, generators, and power grid to minimize system life cycle cost by adjusting the size of the system and optimizing battery dispatch. REeopt further allows for the calculation of resilience and emissions savings. In addition, HOMER (Hybrid Optimization of Multiple Energy Resources) is used to predict the performance of hybrid systems and optimize the size of each component.

Despite the existence of other financial variables or indicators such as levelized cost of energy (LCOE), internal rate of return, or grid parity, NPV appears to be the only indicator which has received significant attention in earlier studies. A more detailed overview of the various financial modeling inputs and alternative approaches to evaluating financial performance of a PV project is provided in Section 4.

2.1.1.3 Selected case studies

Cumberland Forest, Virginia. In 2019, The Nature Conservancy, a nonprofit that originated in the 1950s in Washington, DC and since then grew to an environmental protection nonprofit with operations around the world, acquired 253,000 acres of forest land in South Virginia, East Tennessee, and East Kentucky.[17] The land was previously used for coal mining. It benefits from proximity to transmission infrastructure and features open areas that were subjected to deforestation during the mining process. The objective of The Nature Conservancy is to restore some of the forest and the river and to install PV on the former mine land. The presented plan includes six sites, with about 1,500 acres of land that could be used for 120 MW of solar power. The pre-development effort included site assessments and project design, coordination with mineral interests, local siting and land use agreements, state-level permits, utility interconnection agreements, and a community benefits plan.

Martiki Coal Mine, Kentucky. In 2020, Savion Solar, a Shell Group portfolio company headquartered in Kansas City, Missouri, initiated a project on a reclaimed coal mine in Martin County, Kentucky. The project is designed to convert the 1,200 acre former mountaintop coal mine to a 100 MW PV site by

[14] https://www.nrcan.gc.ca/maps-tools-and-publications/tools/modelling-tools/retscreen/7465
[15] https://sam.nrel.gov/
[16] https://reopt.nrel.gov/
[17] https://www.nature.org/en-us/magazine/magazine-articles/cumberland-forest-project/

2024. A power purchase agreement (PPA) was signed with Toyota Motor North America.[18] The project is expected to employ as many as 300 people during construction, and after completion, it is expected to provide the local economy with $300,000 in annual taxes.

2.1.2 Carbon Capture and Sequestration: Carbon Capture, Utilization, and Sequestration, and Direct Air Capture

2.1.2.1 Carbon Capture, Utilization, and Sequestration

CCUS is the process of capturing CO_2 from the atmosphere or from gas streams and exhaust gas emitted from power plants or industrial processes, the conversion of that CO_2 to products or fuels, and the storage of CO_2 in geologic formations. The most studied CCUS pathway is the capture of CO_2 from gas streams resulting from the combustion of fossil fuels, and the pipeline transport and injection of that CO_2 in geologic formations including deep, saline aquifers, oil and gas formations, basalt formations, and coal mine seams. The utilization of carbon dioxide can include its use as a feedstock for making chemicals and fuels, and its use for enhanced oil and gas production. These applications of CO_2 are not discussed in this report, as they are not specific to the resources and characteristics of mines. Naturally some systems that produce CO_2 and convert it to a fossil fuel substitute could serve fuel demand at a mine, and should not be disregarded just because they are not considered further in this report. Several pre-, post-, or oxy-combustion capture technologies have been demonstrated in pilot projects at ethanol refineries, power plants and other point sources of CO_2. Several pilot projects that demonstrate the safe and permanent injection of CO_2 in geologic formations have also been completed, including CarbonSafe in Wyoming. Only one pilot has been demonstrated on mine land,[19] but numerous formations that could be used for CO_2 sequestration overlap with mine land in the United States.

2.1.2.2 Direct Air Capture

Carbon dioxide DAC is a set of technologies that separate CO_2 from air to allow for removal from the atmosphere (Leotaud 2022). DAC systems based on land and that generate a pure stream of CO_2 rely on either aqueous solutions or solid sorbents for the separation. Other DAC systems that generate a carbonate product use a process called mineralization to capture CO_2. Companies such as Heirloom, Blue Planet Systems, and Capture6 use processes based on mineralization. For solid sorbent–based systems, air enters a DAC unit through a fan until the system is saturated with CO_2. Climeworks and Mosaic Materials are examples of companies that use sorbents. For aqueous systems, air also enters an air contactor through a fan and undergoes a chemical loop using a pellet reactor. The capture chamber is then closed, and a desorption process occurs. Many systems have been demonstrated, with some of the largest capture rates achieved by Carbon Engineering (Keith et al. 2018), Climeworks (Deutz and Bardow 2021), and Capture6. DAC costs have so far not been economical (in many cases, over $1,000/MT net-$CO_2$-removed), although some companies such as Capture6 are beginning to report costs as low as the DOE Earthshot target of $100/MT net-$CO_2$-removed. Climeworks currently captures CO_2 at a cost of $500/MT and sells at more than $1,000/MT. Carbon Engineering captures CO_2 at a cost of $600/MT but has projected it can lower costs below $300/MT. The choice of technology depends on the availability of renewable energy, available thermal energy and/or steam, and input materials. Sorbent materials are currently not manufactured at large scales. With improvements to the performance of the system and component costs, as well as knowledge gained through deployments, DAC systems could potentially

[18] https://pv-magazine-usa.com/2023/05/24/toyota-to-procure-100-mw-of-solar-from-reclaimed-kentucky-coal-mine-site/
[19] https://www.mining.com/co2-storage-project-in-americas-coal-country-one-step-closer-to-becoming-a-reality/

achieve significantly lower capture costs, and even reach the DOE Earthshot target of $100/net-$CO_2$ removed.

The performance and cost of DAC is highly sensitive to the source of energy because separating CO_2 out of ambient air requires energy consumption. For solid sorbents, removing CO_2 requires temperatures around 20°C–95°C (NASEM 2019), making these systems suitable for coupling with low-temperature geothermal energy. Aqueous-based DAC systems vary in their energy requirements, but the most studied technology from Carbon Engineering requires NG for high temperatures (900°C) (Keith et al. 2018). Because energy generation results in upstream greenhouse gas (GHG) emissions, the net reduction in CO_2 from DAC operation is contingent on the availability of low-carbon energy.[1] Climeworks systems in Iceland and Switzerland use heat from geothermal energy and from an incineration plant. The GHG intensity of the geothermal used is approximately the same as wind, at approximately 0.01 kgCO_2eq/kWh. In comparison, the average emission factor for the US grid is close to 0.5 kg CO_2eq/kWh (Chen and Wemhoff 2021).

DAC technologies have so far been designed as modular units that are connected by ancillary equipment such as electricity and thermal energy provision, feedstock and water provision, and CO_2 compression and storage equipment. Although DAC units have yet to be deployed on mine land, there are no technical limitations for a DAC system to be placed on mine land so long as adequate energy, airflow, land, and access for service and maintenance are available. These requirements are described in the following sections. The chemical loop that Carbon Engineering employs to capture CO_2 uses Ca, while Heirloom uses limestone, both of which may be available in mining waste. Systems that generate solid carbonates from mineralization could leverage mining infrastructure for storage and transportation. The subsequent transport and storage of CO_2 will be a necessary consideration for the deployment of DAC on mine land.

Summary

- DAC systems can be coupled with energy sources such as wind, solar, grid, or geothermal.
- The carbon capture efficiency and net CO_2 reduction will be affected by the energy source.
- DAC units are modular, but it is expected some economies of scale will be realized at larger scales, mainly due to the CO_2 clustering, compression, storage, pipeline transport, and injection infrastructure.
- DAC systems require material (solid sorbent or solvent) to be replenished, requiring trucking and storage.
- Many DAC systems require a source of water or steam.
- Local impacts of DAC systems are expected to be low, and are related to land footprint, material disposal, and upstream impacts of energy and material production.
- DAC systems need to be spaced out based on airflow into modular units.

2.1.2.3 Enhanced weathering

Nearly all of Earth's carbon is stored in rocks, which can offer long-term storage. EW, or carbon mineralization, is a CO_2 removal (CDR) strategy that quickens the transfer of carbon from the atmosphere to rocks. This method is a sequestration technology. Existing mining waste such as tailings can react with CO_2 through similar chemical reactions (Stokreef et al. 2022). This already occurs passively to some degree but can be enhanced in several ways, including aeration or injection of CO_2-rich gases into tailings. Case studies suggest EW of tailings could offset 10%–100% of mine operating emissions, depending on the mine and EW practice (Power et al. 2021).

The chemistry of mine tailing carbonation is highly complex and proves to be heterogeneous even within a mine tailing pile. Generally, Mg- and Ca-rich materials react with CO_2 to form carbonate minerals. Ultramafic mine tailings are particularly rich in Mg in the forms of serpentine (Mg-silicate) and brucite (Mg-hydroxide). Materials with Ca-silicate are also of interest. These materials are of interest because they have small grain size and high surface area and thus greater reactivity because of mining practices. They also may be saturated with water, which is an essential ingredient to form stable minerals.

Ultramafic and mafic mine tailings are generated during the mining of Ni, Pt, asbestos, chromite, talc, and diamonds. A recent study also suggested that Fe ore mining waste contains silicate materials and could be used for EW (Chukwuma et al. 2021, Ramli et al. 2021). Globally, there may be as much as 419 MMT of suitable tailings (Power et al. 2020). Mine tailings are sometimes used for backfilling mines and largely do not have a market. It is unclear whether mine tailings that are disposed of in tailing facility impoundments are recoverable. Some materials must be kept saturated to avoid increased surface tension. Quantities are also unclear, but the US Department of the Interior reported in its 2000 Minerals Yearbook, Mining and Quarrying Trends report, that for every ton of material produced from Fe mining, 0.82 t of waste is produced.

Mine tailing composition varies by mine product and deposit. Mine tailings with high concentrations of chrysolite (white asbestos), lizardite (non-fibrous silicate), magnetite, phlogopite, talc, serpentine, and brucite are likely to be reactive with CO_2 (Assima et al. 2014). Brucite in particular can catalyze weathering in tailings (Power et al. 2013). Grain size, temperature and humidity are important variables in determining CO_2 sequestration rates and potential. Using injected CO_2-rich gases can quicken reactions, and numerous engineered pretreatment methods have been proposed, including mechanical, chemical, and biological.

Case studies

There are numerous existing and proposed EW projects on mine land, including the following (Stokreef et al. 2022):

- Active mine: Mount Keith Nickel Mine (Wilson et al. 2014), Australia; 11 MT tailings per year; 17–95 kT CO_2/year total ambient sequestration capacity and 210 kT CO_2/year with CO_2-rich gas (19%–53% of mine's operating emissions)

- Prospective mine: Dumont Nickel Project (Gras et al. 2020), Canada; 1,700 MT waste and tailings over life expected (33 years); 1.4 kg CO_2/m^2/year (21,000 MT CO_2/year, which is 16% of the mine's operating emissions).

- Active mine: Black Lake chrysolite mine, Canada; 4 kg CO_2/m^2/year.

- Inactive mine: Woodsreef asbestos mine (Turvey et al. 2018), Australia; 24 MT tailings total; 11.7 kg CO_2/m^2/year.

- Active mine: Diavik and EKATI kimberlite diamond mines, Canada; approximately 0.4 kg CO_2/m^2/year.

- Active and inactive mines: Clinton Creek and Cassiar chrysolite mines, Canada; 10 and 27 MT tailings total, respectively; 6,200 MT CO_2/year passively sequestered.

- Inactive mine: King City Asbestos Corporation Joe Pit mine, United States; pilot testing serpentine rock waste mineralization.

Demonstration projects at Clinton Creek, Woodsreef, and Mount Keith have documented successful mineralization. However, many of these mines cause passive unintentional mineralization, making it difficult to extrapolate to intentional EW and to understand the natural baseline.

Ultramafic and mafic deposits are mined for metals such as Ni, Co, and Cu, as well as kimberlite, chrysolite, and asbestos. Nickel is very limited in the United States, but the following sites may be candidates for EW:

- In 2021, United States produced 17,000 MT of Ni, principally from Lundin Mining's Eagle mine in Michigan.

- Tamarack Nickel Project in Aitkin County, Minnesota via Tesla.

- 25,200 MT of Ni by 2023, primarily from Canadian firm Polymet's NorthMet mine in northern Minnesota, is possible.

Nine inactive mining sites in California could be investigated for EW, five of which are superfund sites.[20,21] These mines were used to produce asbestos, chromite, and Fe. As new mining technologies allow recovery of products from lower-grade ores, tailings are expected to increase.

Several economic and life cycle assessment studies offer insights on the system-level components and material and energy balances associated with an engineering approach for EW. Studies measuring in situ reaction rates and reactivity have been conducted for a few materials at the lab-scale and in pilot projects, including pulverized Ni ores rich in serpentine and brucite. For outcrop rocks, comminution (i.e., grinding) is used for pretreatment. Some studies have used heat activation of serpentine to remove physi-sorbed water, and at some temperatures, dihydroxylation (McKelvy et al. 2004).

One simple approach to measure the feasibility of reactivity of different deposits is to measure easily extractable cations. Reacting mine tailing materials at temperatures and pressures above ambient can improve reaction rates and reactivity. Power et al. (2021) reported that as little as 20% of materials in mine tailings are reactive at ambient conditions. Pretreating tailings chemically, mechanically, or thermally can increase reactivity.

Comminution equipment runs on diesel and in some cases electricity. Heating reactions will require NG or electricity. Water and chemical requirements of emerging engineering processes are not well understood and are an important research gap. One approach for enhancing mineralization rates is to irritate or spread tailings in constructed greenhouses, which offer elevated temperatures and moisture above ambient conditions.

Powering any necessary equipment with geothermal energy would lower emissions. GHG emissions are translated into global warming potentials. Other impacts associated with electricity and fossil fuel consumption in the United States include acidification, eutrophication, poor air quality outcomes such as

[20] https://www.epa.gov/superfund/abandoned-mine-lands
[21] https://www.epa.gov/superfund

smog formation (low visibility and damage to infrastructure), human health impacts resulting from particular matter, finite material consumption, water withdrawal and consumption, local impacts such as increased traffic, and hazardous air and water pollutant production. Values can be derived from life cycle inventory software and databases such as EcoInvent. Emission factors for diesel and NG combustion are provided by the United States EPA. Negative impacts associated with energy consumption could be mitigated through improving the energy efficiency of comminution and reactor systems, and through using renewable sources of energy. Siting processes and increased trucking away from communities will also reduce local impacts. Hazards associated with these processes include worker exposure to dust (particulate matter), asbestos, and heavy metals.

Summary

- There are several pilot EW projects at current and former mine land around the world, and several mines have been identified as candidates for EW.
- In particular, Ni, Co, Cu, asbestos, kimberlite, chrysolite, and Fe mines likely have mining waste suitable for EW.
- Many candidate mining waste streams have related chemistries, which can help estimate how much CO_2 can be theoretically sequestered (Stolaroff et al. 2005). For example, the percentage of carbonation in a material such as cement kiln dust can be estimated if the amount of CaO, $CaCO_3$, SO_3, MgO, K_2O, and Na_2O are known. In theoretical estimations of carbonation, all CaO is assumed to form $CaCO_3$, and all MgO is assumed to form $MgCO_2$. Similarly, Na_2O and K_2O are assumed to react to bicarbonates or carbonates (Huntzinger et al. 2009).
- However, these wastes are different in their contaminants and their compositions, which will affect the potential waste disposal pathways available.
- Carbonation can happen passively or by intentional aeration of tailing piles or injection of CO_2 rich gases into piles or tailing storage.
    - Passive carbonation will require decisions on waste disposal, land use, and monitoring.
    - Aeration of tailing piles will require the same, as well as jobs for routine aeration or developing the aeration system.
    - Injection of CO_2-rich gas will require the same, as well as a source of CO_2, more intensive monitoring, and more energy.
- Impacts of climate and weather will affect sequestration and necessary water consumption.
- Carbonation can lower risks of tailing piles through cementation.
- Carbon credits can be obtained.

Key research gaps in the field include process design and technoeconomic analysis on EW of mine tailings at scale; developing a baseline for passive CO_2 sequestration potential; modeling capabilities to understand chemical and transport processes in tailing piles; and treated tailing end of life.

2.1.3 Advanced Nuclear Power

Nuclear power has been recognized as a leading clean energy technology. ARs are being developed to make NPPs smaller, modular, inherently safer, and economically competitive, as illustrated in Figure 2-4. Emerging AR design and developments include SMRs and microreactors. Conceptually, an NPP uses nuclear reactions as the source of heat to generate steam but has similar components in CPPs in the electricity generation process: a steam conversion system that feeds steam to a turbine that is connected to a generator to generate electricity, as well as a water supply and condenser. NPPs use uranium fission to create chain reactions and generate heat. Although providing high energy density, they have a small carbon footprint. Furthermore, NPPs produce radioactive waste that must be discharged and stored in controlled conditions.

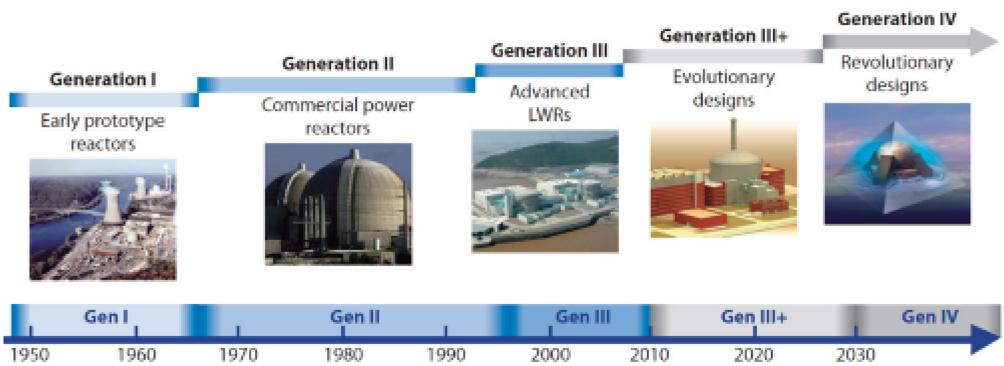


Figure 2-4. Generations of nuclear power: time ranges correspond to the design and the first deployments of different generations of reactors (Generation IV International Forum 2014).

There are a variety of nuclear power technologies (Griffith 2021, Qvist et al. 2021). Water-cooled reactors can be categorized into LWRs, pressurized water reactors, and boiling water reactors. Non–water-cooled reactors include salt- and Na-cooled reactors (e.g., molten salt reactors), high-temperature gas-cooled reactors, and microreactors. Table 2-1 lists operating conditions of selected conventional and ARs.

Table 2-1. Selected NPP operating conditions (Griffith 2021)

Reactor type	NPP design	Power (MWe)	Operating temperature (°C)	Primary pressure (MPa)	Full plant footprint (acres)	Thermal efficiency (%)
Water-cooled	GE-Hitachi, BWRX-300	300	287	7.2	22	33
Water-cooled	NuScale Power, NuScale Reactor	77	300	13.8	35	30
Water-cooled	Holtec SMR-160	160	316	15.5	5	30
Molten salt fast reactor	TerraPower, Molten Chloride Fast Reactor	780	755		16	
MSR	Terrestrial Energy, Integral Molten Salt Reactor	195	600	0.4	17	44
MSR	Moltex, Stable Salt Reactor	400	700	0.1		40
MSR	Kairos Power, KP-FHR	140	650	0.2		44
MSR	TerraPower/GE Hitachi, Natrium		345	540		
HTGR	X-energy, Xe-100	80	565	6	22	41

Table 2-1. Selected NPP operating conditions (Griffith 2021) (continued)

Reactor type	NPP design	Power (MWe)	Operating temperature (°C)	Primary pressure (MPa)	Full plant footprint (acres)	Thermal efficiency (%)
HTGR	General Atomics, Energy Multiplier Module	265	850	13.3		53
HTGR	General Atomics, SC-HTGR	272	750	6		43
Microreactor	Oklo Aurora	1.5	500	—	<1	37.5
Microreactor	BWXT, BWXT AR	17	750	—		
Microreactor	Westinghouse, eVinci	5	750	—	<1	29
Microreactor	Ultra Safe Nuclear Corporation, Micro Modular Reactor	5	630	3		40

MSR: molten salt reactor; HTGR: high-temperature gas-cooled reactor

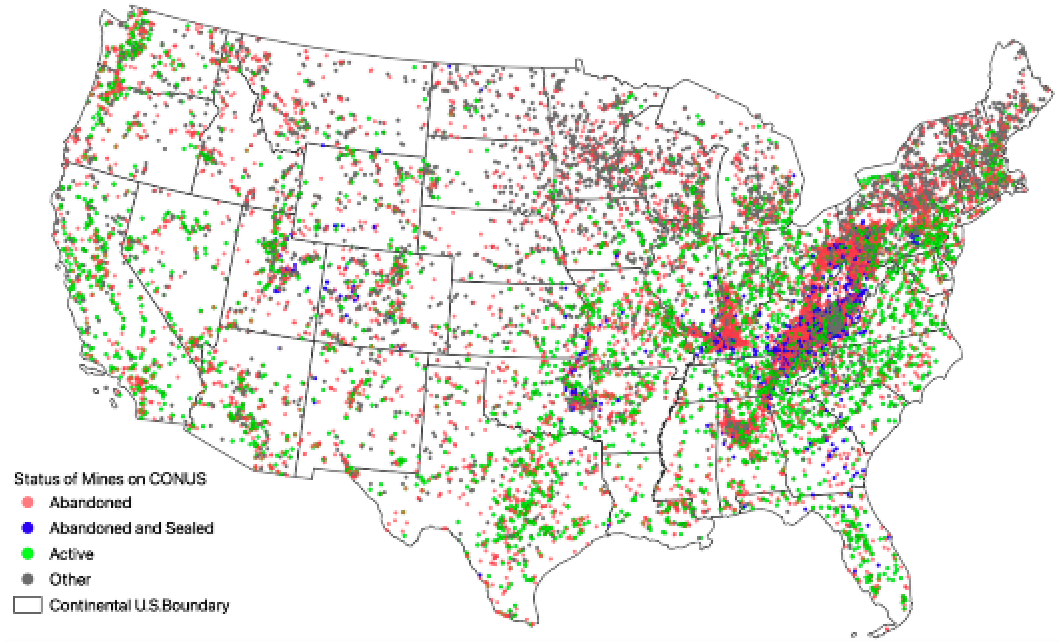
Nuclear power plant site characteristics

Emergency planning zone (EPZ). NPP construction requires delineation of the EPZ. Although current guidelines are based on LWRs, EPZs for SMRs and ARs may be exempted for a smaller boundary. For example, NRC granted Tennessee Valley Authority (TVA) its exemption from the regular 10 mi EPZ for future development of SMRs. Qvist et al. 2021 also found, “All published results of possible severe accidents analysis for novel reactor systems indicate that offsite consequences will not exceed the protective intervention levels at any distance outside of the plant boundary itself.”

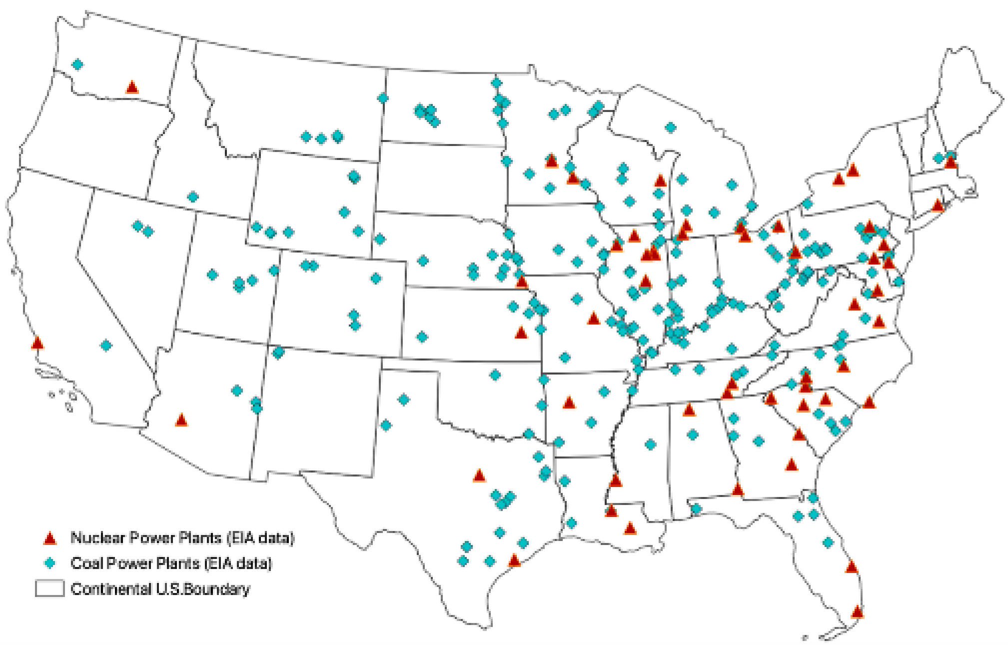
Land footprint. According to the NRC (2019), the size of an NPP ranges from 130 to 70,000 m^2/MW among the 67 US NPPs licensed by the NRC. Newer NPPs will have smaller land footprints as new designs require smaller EPZs. Newer NPPs without cooling towers typically have an approximately 130 m^2/MW footprint, whereas NPPs with natural draft cooling require approximately 500 m^2/MW. Hanson et al. (2022) assumed 50 acres for SMRs, and their siting analysis evaluated ARs within as close as a 0.5 mi site radius (approximately 500 acres) and 1 mi radius (approximately 2,000 acres).

2.1.3.1 Review method

Research on repurposing current and former mine land for NPPs is limited. In practice, nuclear power demonstration projects on mine land are rare. However, plenty of research has been conducted in repowering retired and existing CPPs for NPPs. A comprehensive report by Idaho National Laboratory, Argonne National Laboratory, and ORNL (Hansen et al. 2022) was reviewed as a primary reference. CPPs and coal mines have very different characteristics for repurposing for NPPs. They are also correlated, especially in economic activities. Coal mines supply coal feedstock to CPPs. Therefore, social and economic impacts of one side of the supply chain affect the other side. Also, as shown in Figure 2-5 and Figure 2-6, there is a significant degree of community overlapping or spatial connectivity between CPPs and coal mine land, which means results from regional social and economic studies in repowering retired and existing CPPs for NPPs may indirectly apply to mine land communities. The reusability of infrastructure provides some similarities, such as transportation infrastructure (roads and rail), electricity, and water supply, but may have different characteristics. For example, mine land often has abundant underground water storage. Current and former mine land lacks reusable components in CPPs such as the steam system, electricity generator, and connection to the power grid for electricity delivery. This review is based on general principles required by NPP construction, operation, and regulation. This report intends to identify similarities in methodologies, strategies, and principles with CPP repowering, as well as differences, to provide general guidance for repurposing mine land for nuclear power.



a. Mine land in the contiguous United States



b. NPPs and CPPs in the contiguous United States

Figure 2-5. Spatial distribution of mine land, NPPs, and CPPs in the contiguous United States. Data sources: mine land, US Mine Safety and Health Administration; power plants, EIA. Map projection: Conus Albers equal-area projection.

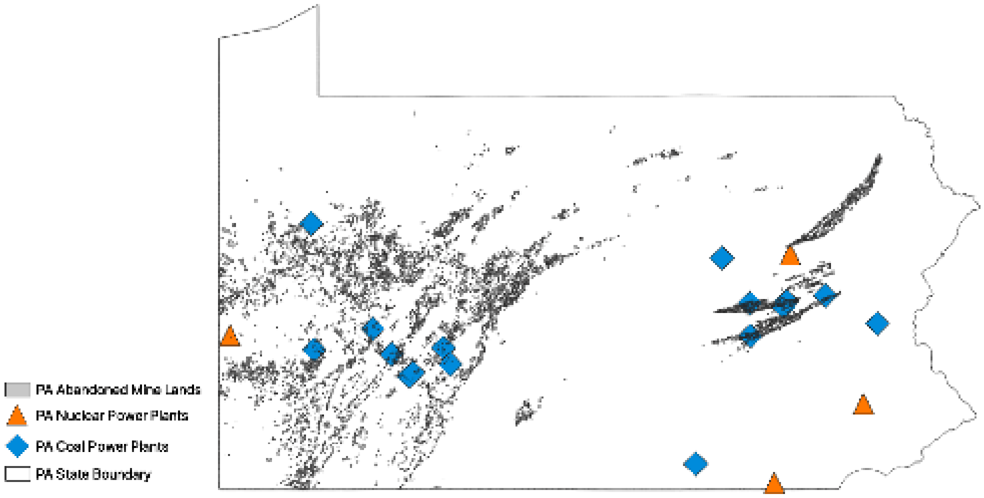


Figure 2-6. Spatial distribution of current and former mine land and existing CPPs and NPPs in Pennsylvania. Data source: EIA and the Pennsylvania Geospatial Data Clearinghouse. Map projection: Web Mercator.

A collection of current and former mine land data sources and existing repurposing efforts are reviewed as relevant data sources for the assessment of nuclear power siting, and for technical and social economic analysis. They include the following:

- e-AMLIS
- Renewable Energy Aggregators
  - Projects
    - Hydropower Highway: hydropower electric vehicle charging stations along highways
    - Old Forge: treating contaminated water and supply over tunneling
- NAAMLP (National Association of Abandoned Mine Land Program)
- Current and former mine land programs at federal agencies:
  - EPA current and former mine land program[20]
  - BLM current and former mine land program[22]
  - US Department of Agriculture Forest Service current and former mine land program[23]
- EPCAMR (Eastern Pennsylvania Coalition for Abandoned Mine Reclamation)[24]

2.1.3.2 Repowering coal power plants for clean energy generation and indications for repurposing mine land

Qvist et al. 2021 compared several clean energy options for the retrofit decarbonization of CPPs in Poland using three criteria: life cycle emissions lower than 50 gCO_2-eq/kWh; annual energy production level of at least 50% of existing coal units; and at least 5% reutilization of existing CPP components. For reusing existing CPPs, multiple levels were considered: repowering CPPs with new low-carbon energy options, adding carbon capture, replacing the coal feedstock with biomass, or replacing the coal boilers. Five new clean energy generation technologies were considered: wind power, solar power, solar thermal power, nuclear power, and geothermal heat source. Although all five options satisfy the emissions criterion,

[22] https://www.blm.gov/programs/public-safety-and-fire/abandoned-mine-lands/about-aml
[23] https://www.fs.usda.gov/managing-land/natural-resources/geology/abandoned-mine-lands#:~:text=There%20are%20approximately%2038%2C991%20total,human%20health%20and%20environmental%20impacts
[24] https://epcamr.org/

wind, solar, and solar thermal fail to produce sufficient energy since annual electricity production from them drops by at least 96% using the areal power density metric. Wind and solar also fail to meet the 5% reutilization criterion. Therefore, only nuclear power and geothermal were discussed. The detailed study found that high-temperature SMRs are the most attractive option to replace coal boilers and can lower the capital cost by 28%–35% and the LCOE by 9%–28% compared with greenfield installation. Water-cooled SMRs cannot directly reuse the steam cycle of CPPs but could still possibly lower the capital expenditure by 15% and the LCOE by 10%. This is a promising result for mine land reutilization for NPPs because of the availability of water resources and related facilities and infrastructure.

Other studies also indicate that nuclear power, especially SMRs and ARs, has great potential for repowering CPPs. Nichol (2022) reviewed the impact from a coal plant closure. Compared with other clean energy options, SMRs offer system benefits of fuel diversity, reliable dispatchable generation, integration with renewables and storage, carbon-free generation, resilience for mission-critical activities (independent operation and protection against threats), and reuse of existing CPP infrastructure. Economic benefits of SMRs include employment (900 jobs for building NPPs; 300 permanent positions for 60+ years of operation; high pay; multiplier effect) and economic activity ($500 million+ economic output annually; $50 million tax annually).

SMR Start (2020) compared land use requirements among SMR, NG combined cycle, wind, and solar energy options (Table 2-2).

Table 2-2. Land use by different clean energy options (per 1,000 MWe) (SMR Start 2020)

Parameter	SMR	NGCC	Wind	Solar
Capacity factor (%)	95	5,513	35	25
Plant life (years)	60 to 80	40–50	20–25	20–25
Lifetime energy (TWh)	647	241	76	55
Land required (acres)	5017	343	85,240	7,900
Land utilization (acres per lifetime TWh)	<0.1	1.4	1,125	144

NGCC: NG combined cycle

ScottMadden (2021) compared jobs, wages, and other metrics among multiple clean energy options with coal and NG and showed that ARs offer high-paying jobs (Table 2-3).

Table 2-3. Comparison of clean energy options vs. coal and NG (ScottMadden 2021)

Generation type	Permanent jobs on site	Industry wage median ($/h)	Carbon free?	Firm energy?	Benefits concentrated locally?
Nuclear	237	41.32	Yes	Yes	Yes
Coal	107	33.64	No	Yes	Yes
NG	30	34.02	No	Yes	Yes
Wind	80	25.95	Yes	No	No
Solar	36	24.48	Yes	No	No

The studies reviewed clearly show that advanced nuclear technologies are a promising clean energy option to repower CPPs. For comparative studies, although power generation criteria may not apply because mine land sites do not generate power, criteria for system and economic benefits may be revised for mine land opportunities.

2.1.3.3 Review: Siting analysis for nuclear power

A siting analysis for NPPs applies a set of exclusion criteria on candidate land or site representation (as geospatial raster or vector) to flag and/or exclude areas or sites that may violate NPP site requirements from site construction, operation, and regulation. Hanson et al. (2022) provided a comprehensive literature review for repowering CPPs for NPPs. This review was based on their work and refers to siting analysis of CPP sites for NPP for guidelines in mine land siting analysis because literature in mine land siting analysis for repurposing is scarce.

For siting analysis, related work cited by Hanson et al. (2022) were collected as follows:

- "Belles et al. (2012) and Belles et al. (2013) are two ORNL studies on an SMR site-screening study using the OR-SAGE tool. In the first part of the study, ORNL enhanced the OR-SAGE tool to specifically handle issues related to SMR siting. The second part of the SMR site-screening study, summarized in the 2013 paper, uses the enhanced OR-SAGE tool to screen a sample of a CPP site with the potential to be repowered with an SMR. The objective of the second part of the study is to demonstrate the capabilities of OR-SAGE in screening CPP sites for SMR repurposing, rather than to comment on the suitability of specific CPP sites. The sample of 34 CPP sites was chosen based on their nameplate capacity, which opted for older and smaller CPPs. The coal stations selected for screening were evaluated and assigned to a rating of "good," "better," or "best" based on their site selection and evaluation criteria."

- "Belles et al. (2021) evaluated 13 CPP sites in the Tennessee Valley Authority (TVA) service territory to determine the potential of these sites for SMR siting. The TVA CPP sites are a mix or existing and former sites and are evaluated using the OR-SAGE tool. OR-SAGE evaluates the sites based on established industry and regulatory criteria and available data. The results of the analysis conclude that most of the sites evaluated are suitable locations to site an SMR."

- "Qvist et al. (2021) assessed retrofit decarbonization options of the Polish CPP fleet. Using the Polish CPP fleet as a case study, the authors compare the benefits of many retrofit decarbonization options including, adding carbon capture, converting to biomass feedstock, converting to NG and carbon capture, switching out coal boilers for nuclear reactors, wind turbines, solar PV panels, geothermal power, and more. After evaluating each option on many criteria including, ability to reutilize existing equipment, match thermal output, and ability to handle water scarcity issues, the authors find that the most attractive retrofit decarbonization option is using high-temperature SMRs. With this option, overnight capital costs and LCOE are found to be lower than in a greenfield installation."

- "Griffith (2021) focused on presenting near-term issues that need to be considered by utilities and stakeholders in replacing a CPP with an NPP. Some of the presented and discussed issues include decommissioning efforts of a CPP, siting conditions, the basics of generating energy, NPP and CPP matching, and other factors in replacing a CPP with an NPP. Griffith also discusses the potential options, each requiring varying levels of technical and socioeconomic considerations, of replacing coal power with nuclear power. To demonstrate how these considerations can be applied and how viability can be assessed, Griffith presents an example case study of a [CPP to NPP] transition at the Colstrip Plant in Montana. In addition to Griffith's study, the Gateway for Accelerated Innovation in Nuclear (GAIN) Initiative is leading an effort of community engagement to facilitate coal-community understanding of [CPP to NPP] impacts."

- "TerraPower (2021) described the [CPP to NPP] project underway in Kemmerer, Wyoming, to transition the Naughton CPP infrastructure for use in a Natrium NPP sited nearby. The remaining two units of the Naughton Power Plant are planned for retirement by 2025. TerraPower and its partners on the project evaluated many factors in determining the suitability of the site, such as access to existing infrastructure, grid demand, site characteristics, and the ability to obtain a license for the site from NRC. According to TerraPower, the local community and communities across Wyoming have expressed their support for the demonstration project."

- "The EPRI (2019) considered the plant retirement and redevelopment process of coal sites from a wide range of topic areas, addressing key considerations, barriers, and potential actions to building a strategy or approach for site repurposing or redevelopment of retiring coal plants. To develop a comprehensive and holistic repurposing approach, EPRI seeks to assist its members by presenting and discussing case studies of repurposed sites, ongoing repurposing initiatives, funding benefits, and recommended next steps. While this study does not specifically focus on replacing retired coal plants with advanced nuclear, EPRI plans to complete a report on repowering coal-fired power plants for advanced nuclear by the end of 2022."

In general, siting criteria for NPPs can be categorized into population, geologic and seismic considerations, water considerations, and other considerations such as hazardous conditions and proximity to protected lands (Hansen et al. 2022). These criteria apply to both repowering CPPs and repurposing mine land.

Qvist et al. (2021) provided a detailed siting criteria table, as described in Table 2-4. They also discussed other hazardous conditions to be considered for site exclusion, including extreme wind speed, flooding, and extreme snow or rainfall.

Table 2-4. Technical site requirements comparison: coal and nuclear (Qvist et al. 2021)

Parameter	CPP	NPP
Fuel delivery	Up to several million tons per year	Low volume and infrequent
Cooling water: (a) Direct cooled (b) Tower cooled	(a) 3 m^3/s per 100 MWe (b) 0.2 m^3/s abstracted, about 0.05 m^3/s evaporated per 100 MWe	
Geology	Ground able to support heavy loads	Seismically stable ground able to support heavy loads with virtually no differential settlement
Access: (a) Construction materials (b) Abnormal loads	(a) Road, rail, or sea access to deliver up to >1 million tons (b) Road or sea access to deliver about 80 large loads	
Waste disposal	Means of disposing of up to 60,000 tons per year of ash per 100 MWe	Near to railhead or port for transport of irradiated fuel
Special considerations	Delivery of about 20,000 tons per year of limestone and disposal of about 30,000 tons per year of gypsum per 100 MWe	Subject to nuclear regulatory approval and local social acceptance for siting
Grid integration	Suitable for connection to a point on the grid able to accept output of station	

Xu et al. (2022) studied the potential of repowering CPPs in China for NPPs. In their work, a three-phase strategy was proposed to expand the repowering effort spatially from a coastal area to an inland area with better readiness and adjacent to coast and finally to a remote inland area. They selected five ARs for the retrofit decarbonization study, among which one was an SMR. Four use liquid metal cooling and one uses supercritical water cooling. The siting criteria are identical to those from Qvist et al. (2021). There are a few unique siting considerations. When deciding EPZs, plume EPZ with a radius of 7–10 km implements evacuation plans, stable iodine intake, and food and drinking water control, whereas an ingestion EPZ with a radius of 30–50 km provides protective measures such as flood and drinking water control. Infrastructure support for transporting overweight and oversized parts, as well as nuclear fuel, spent fuel, and solid waste, was given particular attention. In seismic criteria, requirements on the size, type, scope, and detail level of seismic survey data were specifically mentioned. The work also concluded that high-temperature SMRs are attractive for repowering CPPs.

Hanson et al. (2022) provided a major study on site analysis for NPPs. In this work, OR-SAGE was employed to evaluate 157 retired CPPs and 237 operating CPP sites in the United States for the potential of converting to renewable power plants (RPPs), using data obtained from EIA. To perform site-specific analysis on retired CPPs, initial reviews were carried out on 841 retired sites to remove those that did not have attractive reusable infrastructure, were too old, or had a limitation in ownership. Then, OR-SAGE was applied on the remaining 229 retired sites to score each site at each GIS layer. Each GIS layer represented a siting criterion.

NRC 10 CFR 100 and NRC RG 4.7, as well as the EPRI siting guide (Rodwell 2002), provide nominal reactor siting considerations for siting criteria definition. Table 2-5 shows an example set of siting criteria in OR-SAGE.

Table 2-5. Siting criteria in OR-SAGE (Rodwell 2002)

k	Criteria description	Condition for cells elimination	
		AP1000	**Xe-100**
1	Population density (PD)	PD ≥ 500 people per square mile within 20 mi	PD ≥ 500 people per square mile within 4 mi
2	Protected land (PL)	Classified as a PL	Classified as a PL
3	Safe shutdown earthquake (SSE)	SSE > 0.3 g	SSE > 0.5 g
4	Landslide hazard (LH)	Moderate or high LH	Moderate or high LH
5	Fault lines (FL)	Close to FL	Close to FL
6	Hazardous operations (HO)	Close to HO	Close to HO
7	100 year floodplain region (FPR)	In FPR	In FPR
8	Wetlands or open (WLOW)	Classified as WLOW	Classified as WLOW
9	Slope	Slope > 12%	Slope > 18%
10	Streamflow (SF)	SF ≤ 135,000 gpm	Not applicable

Population. NRC 10 CFR 100 specifies population density requirements based on potential radiation dose. NRC RG 4.7 recommends population density of less than 500 persons/mi^2 for an LWR and at least 20 mi radial distance. NRC prepared SECY 20-0045 as a revision to the emergency planning and calculation of radiological consequences for SMRs and ARs. It provides guidelines on whether to exclude areas with more than 500 persons/mi^2 based on the low population zone size and the exclusion area boundary size, as well as dose exceeding 1 rem over 20 days. This guideline often produces a small value of population density. Hence, TVA established a 2 mi exclusion population zone. OR-SAGE assumes 4 mi in a more conservative way. At a 4 mi range, many CPPs failed to satisfy the population criterion and are thus excluded for NPPs. Mine land, on the other hand, if located in remote areas, will likely meet the population criterion.

Geologic considerations. Seismic restrictions, proximity to fault lines, steep slopes, and landslide risk are geologic considerations for flagging CPP sites. A threshold for the safe shutdown earthquake peak ground acceleration (2% chance in a 50 year return period) is set to flag CPP sites. For LWRs, OR-SAGE sets it to be equal to 0.2. For SMRs and ARs, it is relaxed to 0.5. For fault line proximity, NRC 10 CFR 100 specifies a lookup relationship between fault line length and standoff distance from an NPP site, which OR-SAGE uses as a geologic criterion. Slopes steeper than 12% for LWRs and 18% for SMRs and ARs are flagged. On land slide risk, OR-SAGE uses USGS landslide data to flag moderate- to high-risk areas.

Water considerations. NPP sites with water-cooled reactors need to be in proximity to a water source. Conflicting water considerations for siting include wetlands and open water, as well as areas that lie within a designated 100 year flood plain. Detailed considerations are quoted below from Hanson et al. (2022):

"For reactor technologies that require a water-based ultimate heat sink, OR-SAGE assumes a closed-cycle cooling system with freshwater makeup water requirements. Cooling water makeup requirements are based on best practices for cooling water makeup required per megawatt of generation. These practices are consistent with environmental analyses supporting site evaluations submitted to NRC. A subset of reactor technologies can be bounded by a threshold makeup need, and a siting assessment for a makeup cooling water need can be evaluated. In this case, the threshold parameter value is selected based on the largest megawatt electrical rating of the nominal reactor technology configuration (e.g., single plant, multi-module). Additionally, based on the EPRI siting guidance, cooling water makeup should be limited to taking no more than 10% of the available stream flow. This limits the siting of reactor plants to the vicinity of streams with sufficient flow volumes. The EPRI guidance further recommends that the cooling source be within 20 mi to provide reasonable proximity to a cooling water source, allowing for piping and pumps. OR-SAGE has several preset makeup water values for selection as the threshold value of interest. Other methods for providing the plant ultimate heat sink include saltwater, aquifers, gray (sanitized) water, and air cooling. Alternative cooling water sources are not directly modeled. This layer is not modeled for AR technologies under the assumption that they can use the atmosphere for their ultimate heat sink. So, this OR-SAGE layer does not exclude any coal plant analyses for ARs. However, the backfit of large LWRs at certain coal plant sites was considered in this report. Therefore, the discussion on a cooling water evaluation layer is valid."

Protected lands. "Protected lands include national parks, national monuments, national forests, wilderness areas, wildlife refuges, wild and scenic rivers, state parks, county parks, American Indian lands, BLM, hospitals, colleges, schools, and correctional facilities. These lands are excluded based on their public nature or special use. Exclusions based on the individual data sets are fixed; however, any given protected land data set can be turned off for special consideration. For example, the American Indian lands layer could be turned off if there were interest in siting a facility on American Indian land." (Hansen et al. 2022)

Vicinity to hazardous facilities and operations. "Land in the vicinity of facilities that could pose a hazard to the safe operation of a reactor include commercial airports, chemical facilities such as oil refineries, certain energy facilities such as NG compressor stations, and military bases. The vapor plume from any associated reactor cooling water tower could also pose a risk to a nearby commercial airport. Commercial airports are identified with a 10 mi buffer in the OR-SAGE database. Chemical and energy facilities are identified with a 5 mi buffer, and military facilities are identified with a 1 mi buffer. Cells that fall inside the buffer zone for one of these facilities are flagged for further analysis. In the case of airports, this could be a risk assessment to further evaluate the runway orientation and the operations tempo. Military bases may be considering siting a reactor on the facility. In this case, the exclusion layer for military bases can be removed." (Hansen et al. 2022)

After OR-SAGE site flagging, 157 retired sites were selected for an expanded review, which provided an aggregated view of retired sites. In total, 79% of the eliminated sites in this step were attributed to population constraints. Next, the expanded review was done by siting within a 0.5 mi radius (500 acres) and 1 mi radius (2,000 acres) of the site central point. Siting criteria in the expanded review within a 0.5 mi radius are listed in Table 2-6.

Table 2-6. AR 0.5 mi radius evaluation criteria (Hansen et al. 2022)

Parameter	Trip conditions
Population density >500 ppsm within 4 mi	Flagged if >50% of the 208 cells exceed the threshold Tripped flag assigned a score of 20 (all other AR flags assigned a score of 1) Allows sites that are population limited to be readily identified
Safe shutdown earthquake	Flagged if >50% of the 208 cells exceed the threshold
Faults	Flagged if >50% of the 208 cells exceed the threshold
Protected land	Flagged if >30% of the 208 cells exceed the threshold Provides a higher sensitivity to the proximity of protected land
Slope	Flagged if >50% of the 208 cells exceed the threshold
Landslide	Flagged if >50% of the 208 cells exceed the threshold
Wetlands and open water	Flagged if >60% of the 208 cells exceed the threshold Provides a lower sensitivity to the proximity of water because coal plant sites typically have numerous ponds on site in addition to the cooling source
Floodplain	Flagged if >40% of the 208 cells exceed the threshold Provides a higher sensitivity to the proximity of floodplains
Hazardous facilities	Flagged if >50% of the 208 cells exceed the threshold
Sum flag scores	Dismisses sites with a score of 20 or higher (reflects a population density trip); ranks remaining sites by score, presence of a dedicated cooling source (as opposed to once-through cooling from a river or lake), and years since retirement

Amenable sites were selected based on the scores. Table 2-7 describes that among 157 retired sites, 125 are AR-amenable using the 0.5 mi radius analysis. Population, again, is a major constraint in eliminating candidate sites. Sites with dedicated cooling source are favored as proximity to water resources is an important economic factor for water-cooled ARs.

Table 2-7. Summary of retired sites evaluated for AR backfit within a 0.5 mi radius of the plant center (Hansen et al. 2022)

Region	Sites	AR-amenable 0.5 mi	CPP retired in past 6 years 0.5 mi	Dedicated cooling source
Midwest	60	41	27	13
Northeast	18	15	9	4
Southeast	50	45	17	11
Southwest	13	13	11	7
West	16	11	3	2
Total	157	125	67	37

The review of operating CPP sites follows a similar siting process. Results show that operating CPP sites are more amenable for backfit for NPPs than retired sites because retired sites tend to degrade quickly. Dedicated cooling source also plays an important role in backfitting operating CPP sites for NPPs.

In summary, the siting analysis done by Hanson et al. (2022) shows that across the recently retired CPP sites selected for evaluation, 80% are conducive for siting ARs, and 22% of those sites are amenable to siting large LWRs. The analysis also shows that of the evaluated operating CPP sites, 80% are amenable to siting an AR, and 40% are amenable to siting an LWR.

2.1.3.4 Review: Technical and commercial potential

CPPs share many commonalities with NPPs (Hansen et al. 2022): both operate large-sized generators in baseload; both rely on heating water to generate steam for power conversion (the difference is the source of heat—coal combustion or nuclear heating); both operate turbomachinery; both manage waste heat; and both transform and transmit electricity to the power grid. Such commonalities provide CPPs with great potential for component reutilization. Hanson et al. (2022) listed common CPP and NPP components from the Energy Economic Data Base (Deline et al. 1988): land and land rights; yard work; administration and service buildings; electric switchyard buildings; transportation and lift equipment; air and water steam service systems; communication equipment; and furnishing plus fixtures. Qvist et al. (2021) classified reutilization of CPP components into site reuse, equipment reuse (transformer station and grid connection), interface integration (external heat connections), process integration (turbines, generators, and condenser cooling), and complete reuse (reusing coal boiler for biomass boiler; carbon capture and storage). Similarly, Hanson et al. (2022) classified different potentials of reusing CPP components into greenfield construction NPP, reuse of site, electric and heat sink components only, and direct and indirect reuse of steam cycle components.

In contrast to the commonalities between CPPs and NPPs, mine land does not have such high commonality, limiting the reusability of existing infrastructure on mine land. The EPA (2020) RE-Powering report identified four types of infrastructure that may be present on current and former mine land for reuse: electricity transmission and distribution system equipment, physical security (protective electric equipment), dormant power generation, roads, and civil and structural facilities.

Even for CPPs, compatibility with NPPs from site, electric, steam cycle, and heat sink perspectives are to be carefully considered and matched (Hansen et al. 2022). Environmental conditions such as the level of required cleanup apply to both CPPs and mine land. Mine land sites expose more reclamation and cleanup concerns in public safety, environmental restoration, and contamination cleanup.

To reuse CPP sites, Xu et al. (2022) mentioned that modular design and construction can reduce site area by 25%, and a full utilization of existing CPP equipment and buildings may further reduce the required site area by 25%. Consequently, the site land footprint can reduce from a CPP's 650 m^2/MW to 325 m^2/MW.

Electric compatibility requires the total power of new NPPs to be the same as or less than existing CPPs to reuse transmission components in CPPs without significant upgrade costs. Qvist et al. (2021) noted that the steam temperature required by new heat sources dramatically affects the reutilization of CPP assets. CPPs operate at high steam temperature; as the required steam temperature decreases, steam cycle equipment (e.g., steam turbine, generator, condenser cooling system), process heating heat exchanger connection, electric grid connection, and distinct heating heat exchanger connection become less reusable in that order. CPP steam temperature is often in the range of 500°C to 600°C, while the operating temperature of water-cooled SMRs and ARs is below 300°C. AR technologies such as Na fast reactors and high-temperature gas-cooled reactors that use liquid metal or gas coolant operate at higher temperature and thus have more potential to reuse CPP steam cycle equipment (Hansen et al. 2022).

Because of different thermal efficiencies between CPPs and NPPs, matching a nuclear heat source may require multiple coal units with the same thermal power rating. Therefore, reusing a CPP heat sink may require reapproval or permitting (Hansen et al. 2022). CPPs often use heat sink technologies that require power to operate (e.g., mechanical draft cooling, direct cooling), whereas NPPs tend to use natural draft cooling towers without the need of power for operating. Therefore, reusing CPP heat sink systems may avoid new investment costs but introduces reduced system efficiency with the additional power consumption (Hansen et al. 2022). Qvist et al. (2021) mentioned that adding a thermal storage system to a smaller heat source is an interesting feature to be further explored to reuse existing large-capacity steam turbine system.

Reusing mine land infrastructure for NPPs is rarely discussed in the literature. Site and electric component reutilization may have some potential for reuse, but further study needs to be conducted to gain more information.

Hanson et al. (2022) conducted a technical compatibility and decision-making simulation for repowering CPPs to clean generation options using the agent-based capacity expansion method based on the Argonne Low-Carbon Electricity Analysis Framework for Illinois. Demand and generation data were obtained as hourly data from the NREL Cambium data retrieve tool. Two agents were designed to represent large flexible utility firms that have more cash flow for considering more active repowering options and small firms that adopt conservative spending strategies to secure the minimum invest coverage ratio. Both agents optimized two objectives: maximum return and maximum firm liquidity. The results show that the large agent can repower CPPs with NPPs given their flexibility in investment, whereas the smaller agent could only retire CPPs and explore low-cost options such as wind power.

2.1.3.5 Review: Social and economic impact

Hanson et al. (2022) also compared social and economic impacts between CPPs and NPPs in terms of jobs, taxes, economic growth, and emissions. Similar to the overnight construction cost analysis method that is broadly applied in NPP domain, the methodology of regional economic input/output analysis using IMPLAN software was applied. Both methods intentionally ignore transition effects and output results that reflect the steady-state equilibrium where a CPP or an NPP is in place. Overall, the analysis results showed more than 600 new jobs in the region of study in employment impact, $275 million additional economic activities, and an increase of 92% tax revenue if two units in a CPP are converted to two SMRs. The environmental analysis showed a reduction of GHG emissions by 86%, as well.

Regional socioeconomics

To prepare for the input/output analysis, a regional economic profile of the communities surrounding the power plant of interest was established from several data sources (Hansen et al. 2022). First, work commute data from the US Census Bureau (2022) and proximity to nearby cities were considered to select counties of impact. Second, using the set of social parameters defined by EPA (2022), a regional socioeconomic summary was created to evaluate the counties of interest and their ranking in the state and the nation. The socioeconomic and education parameters included population, race, income, demographic index, median housing value, median household income, civilian labor force, unemployment rate, persons in poverty, persons with high school diploma, and persons with bachelor's degree. Finally, a regional employment summary by industry was compiled to understand electricity generation sector's standing among other industry sectors.

Electricity generation profiles

To establish electricity generation profiles, the CPP capacity was obtained, and its emission was calculated using the capacity data. Specifically, the emission amount was computed as

Emission (CO_2 lb/h) = CPP capacity (MWh) × capacity factor (49.3%) × average CO_2 emission (lb/MWh).

The capacity factor was obtained from Statista (2022) and the average CO_2 emission was from EPA eGRID (EPA 2019).

Repowering alternatives

Given the number of generating units in an existing CPP, their capacities, and the number of employees needed to operate each unit (75 employees for 617 MWh), four repowering alternatives in a progressive repowering sequence were considered by Hanson et al. (2022): preclosure with normal operation; half-closure with half of the units shut down; coal and nuclear mixing; and full nuclear repowering. The nuclear reactor profile of the six-unit NuScale SMR (i.e., 462 MWe with 193 employees) and TerraPower SMR (245 MWe with 250 workers) were used as the corresponding nuclear unit profile.

Economic impact

Results from Hanson et al. (2022) demonstrated the impact of CPP to NPP conversion on employment, output, labor income, value added (i.e., the contribution from electricity generation to gross domestic product in the region of study), and county tax. The impact of direct employment is evident since both SMRs need more employees to operate than a CPP unit. The employment impact among direct, indirect, and induced effects is evenly distributed, though. The value of industry output, measured as the annual production, increased from \$284.8 million for all-coal to \$552.7 million for all-nuclear. This increase occurred because company earnings are directed more to local employees, which are spent locally instead of on nonlabor input such as obtaining coal feedstock from outside. The labor income impact results showed that the total employee income and benefits increased from \$25.5 million for all-coal to \$142.6 million for all-nuclear. The value-added impact analysis indicated that the value added to the supply chain increased from \$131.8 million to \$293.4 million. IMPLAN was used to estimate tax revenue impact. The results showed a total tax increase of \$46.5 million from all-coal to all-nuclear—a 92% increase. County-level tax increased by 59%; state tax increased by 64%; and federal tax decreased by \$4.6 million because of rebates and subsidies.

Environmental impact

IMPLAN takes the input of industry output to evaluate industry specific environmental factors by using EPA's Environmentally Extended Input-Output model data. Results showed reduction of GHG by 99% in direct impacts and by 86% in combined direct, indirect, and induced impacts (Hansen et al. 2022). If compared using the same number of employees, the estimated total environmental impacts across criteria pollutants, GHG, land use, mineral use, nitrogen and phosphorus release to water, toxic chemical release, and water use are all reduced after the conversion to an NPP. The only increase is from pesticide emissions.

Workforce transition

Data from the US Bureau of Labor Statistics (BLS) employment matrices and the IMPLAN Occupational Data were used to study the job gains and losses in CPP to NPP transition. Occupation-by-occupation comparison results were produced. The BLS (2022) study compared the top 10 fossil fuel jobs and top 10 nuclear jobs. The BLS results showed that a net gain of 196.29 jobs is achieved after transitioning to an NPP. There is not a perfect match between fossil fuel and nuclear jobs. To assist the evaluation of how much effort is needed to transition workforce (e.g., direct transition, training/education, financial support), a comparison of educational background between coal and nuclear jobs was presented.

2.1.4 Pumped Storage Hydropower

PSH represents the largest source of energy storage in the United States, accounting for 93% of utility-scale storage power capacity (GW) and more than 99% of electrical energy storage (GWh) in 2019 (Uria-Martinez et al. 2021). PSH energy storage systems operate by transferring water between an upper water body and a lower water body, generating electricity when the water flows downhill and using pumping power to return the water uphill for storage and later generation. Physically, projects may be operated as open-loop (continuously connected to a naturally flowing water feature) or closed-loop (not continuously connected to a naturally flowing water feature). Comparatively speaking, closed-loop systems offer several benefits, including fewer environmental impacts and a shorter licensing decision timeline (2 years).

Currently, 42 open-loop PSH projects are operational in the United States, totaling 21.6 GW in installed capacity. Only one closed-loop project is operational, totaling only 0.04 GW. Historically, most pumped storage development occurred in the United States during the 1960s through the 1990s (Hadjerioua et al. 2020); however, more recent increases in deployment and expected future growth of variable renewable energy resources (primarily wind and solar power) has increased the need for energy storage, capable of meeting grid demands throughout the day. As by far the most-deployed and most-proven energy storage technology, PSH offers one of the best solutions for meeting future energy demands.

With rapidly evolving demand for energy storage, applications for regulatory permits and licenses for PSH projects have increased considerably in recent years. According to data maintained by ORNL (Johnson and Uria-Martinez 2022), the US project development pipeline included 79 closed-loop PSH projects (totaling 50.9 GW in power potential) and 17 open-loop PSH projects (totaling 21.7 GW in power potential) (Figure 2-7).

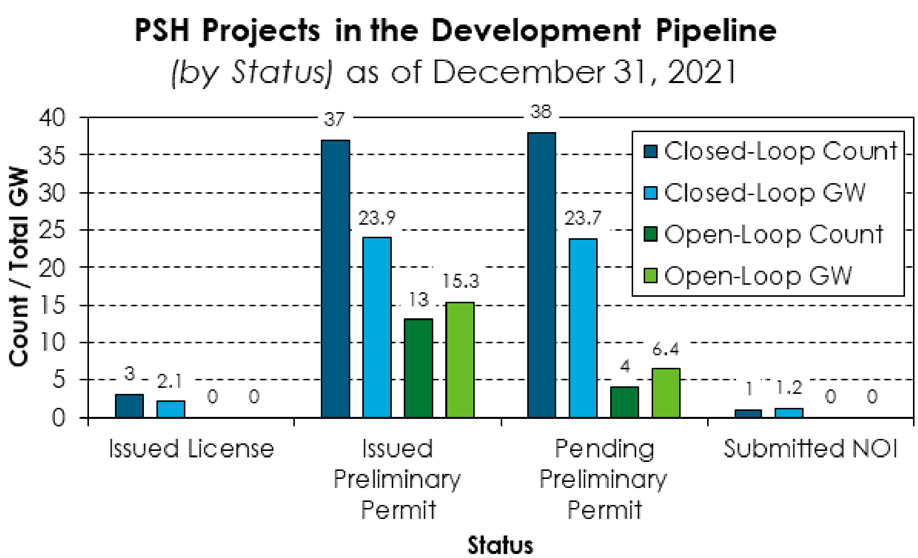


Figure 2-7. US PSH development pipeline, by status and operational configuration. Data source: Johnson and Uria-Martinez (2022).

While no operational PSH projects are currently sited on former mine land, numerous pipeline projects have been proposed to utilize mine land. An estimated total of 13 PSH mine land projects are currently in the pipeline, totaling 3.42 GW in proposed power potential; all 13 projects are closed-loop designs. While none have become operational, one project (Eagle Mountain) has been issued a license by the Federal

Energy Regulatory Commission (FERC). The rest either have been granted a preliminary permit or have a pending preliminary permit.

PSH projects for mine land may leverage surface mine land application (referred to as "open pit PSH") or underground mine application (referred to as "shaft PSH"). These terms are used throughout the remainder of this report.

2.1.4.1 Technical challenges

The principle for open pit PSH is the same as traditional pumped hydropower and may be most effectively designed as closed-loop (Figure 2-8). Open pit mine PSH may utilize a single mine as an upper or lower reservoir and require a secondarily constructed reservoir or may use two co-located mines that are of different elevation. Open-loop open pit mines could also be possible, though they would require more environmental study. Reservoir storage volume, water flow rate, water hydraulic head, estimated installed (power) capacity, water quality, and seismic/geological stability and hydrogeology are all key technical considerations, among others.

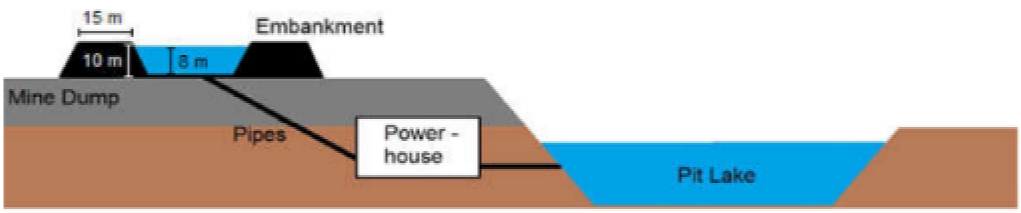


Figure 2-8. Surface application pumped hydropower.

Reservoir storage volume

The first criterion to consider is the total volume of water that can be used for generation. This parameter is constrained by the physical site characteristics present at a mine, including the geologic stratification which may be conducive to excavation and construction. Manufactured PSH reservoirs are typically semi-conical in nature, with storage being a function of maximum water depth, full-pool area size, reservoir bottom area size, and embankment slope.

Existing research shows that the capacity costs of PSH on an open pit mine decline substantially as volume increases from 1 to 5 megatons, and then levels off as volume reaches 8 megatons or above, and NPV consistently increases with the increase of the storage volume (Wessel et al. 2020).

Water flow rate

Water flow rate is constrained by the smallest of the upper reservoir storage volume and the lower reservoir storage volume. The other parameter to consider is the desired power generation duration. Typically, most PSH projects operate on a daily basis, generating power for 4–10 h (Kortarov et al. 2022) and using additional time during the day to return water to the upper reservoir.

A simplified calculation of total water flow rate can be performed according to Eq. (2-1). Total flow rate may be split among different penstocks to supply multiple pumps/turbines (or reversible pump-turbine units).

$$Q = V / t \,, \tag{2-1}$$

where Q is the total water flow rate (cms), V is the minimum reservoir storage volume (m^3), and t is the flow duration (s).

Water hydraulic head

The water hydraulic head varies as the upper and lower reservoirs are filled and emptied. Hydraulic head is measured as the elevation difference between the upper and lower reservoir surface water elevation, minor energy losses and water flows through the water conveyance system.

Estimated installed (power) capacity

The turbine(s) and pump(s) installed in a PSH powerhouse are sized to meet the design head and flow for each unit. The power generated by an individual turbine is a function of water density, flow rate, gravity, and head, as calculated in Eq. (2-2).

$$P = 1000 * q * 9.81 * h \, , \qquad (2\text{-}2)$$

where P is power potential (W), q is the unit water flow rate (cms), and h is the water hydraulic head (m).

Water quality

Water quality is a significant factor in the development of PSH in open pit coal mines for a variety of reasons. The first reason is that open pit mines naturally accumulate water, which requires occasional water releases, and would probably require water releases before the pits can be waterproofed and repurposed. The second reason is that if the waterproofing of the reservoirs is imperfect, it may create conditions for contamination of water from being in contact with potentially toxic substances.

Existing research (AECOM Australia 2019) suggests that water quality is mitigated for the inclusion of a wide range of chemicals, including As, Cd, Se, Pb, Zn, Mn, nitrogen, Cr, and sulfur. Water quality is further checked for pH and dissolved mineral solids.

Seismic/geological stability and hydrogeology

Geological stability can present a limiting factor for the whole PSH setting. If the upper reservoir has been artificially built of the material from the main pit, this may create the conditions for subsidence of the walls of the reservoir (Wessel et al. 2020). The stability of both reservoirs would also be required to maintain waterproof properties.

The inflow of water to the open pit pumped hydropower reservoir during the construction stage is analyzed for velocity, shear stress, flow width, flow depth, stream power (AECOM Australia 2019). Existing research assumes that in the operating stage, reservoirs would be waterproofed using cement or asphalt liners to prevent the outflow of water and water contamination due to contact with toxic substances and to maintain water storage; use of geomembrane liners may also be effective. The drainage area characteristics may affect how much surface water can channel into the reservoirs. Significant rainfall events are seen as factors that can contribute to recharge of the reservoirs but may also cause an overflow and transport of sediment into the reservoirs. Subsurface water recharge is also a consideration, and many proposed PSH projects consider the use of subsurface water for the initial reservoir filling.

Other considerations

Other considerations such as generating equipment or open-loop vs. closed-loop structure of the PSH project are not specific to current and former mine land and therefore are not covered through the separate review of existing research.

Little infrastructure-related information is available in the open literature, though mines are often served by roads, railroads, and power lines. It is known from media reports that a PSH plant usually requires new transmission equipment. This usually includes a substation, but some projects also require new transmission power lines. This may be a direct consequence of expanding peak capacity of the site.

2.1.4.2 Financial characteristics

In power markets, the main sources of revenue for pumped hydro projects are arbitrage revenue from active power markets and the revenue from ancillary services such as regulation and reserves.

The exact costs of converting an abandoned open pit mine into PSH depend on the specific characteristics of the mine. However, the main cost components can be established based on existing research. The main cost areas include the following:

- Reservoir groundwork, tunneling, waterproofing
- Waterway costs, tubes
- Generators, turbines, pump, network, communication
- Roads, transmission lines, substation equipment, security systems, landscape work
- Construction equipment, labor
- Insurance, financial interest

The main approach to evaluating the technoeconomic feasibility of an open pit PSH project is using NPV (Witt et al. 2015). According to existing research, there are multiple ways to generate revenue from pumped hydropower systems. A pumped hydropower facility can sell its output at fixed contracts or through an open market, in the latter event total revenue stream can come from energy and ancillary services markets. Standby capacity represents another stream of revenue. Further detail about financial modeling of pumped hydro is provided in Section 4.

2.2 SUBSURFACE APPLICATION

2.2.1 Pumped Storage Hydropower

2.2.1.1 Technical challenges

The existence of a vertical shaft in mines creates conditions for underground PSH. A general layout of an underground PSH facility is illustrated in Figure 2-9. The upper reservoir is built above the surface, either by excavating or through a structural volume of materials lifted from the mine. The lower reservoir is composed of caverns and tunnels in the subsurface part of the mine. The two reservoirs are connected by a vertical or sloped shaft which is used as the main waterway.

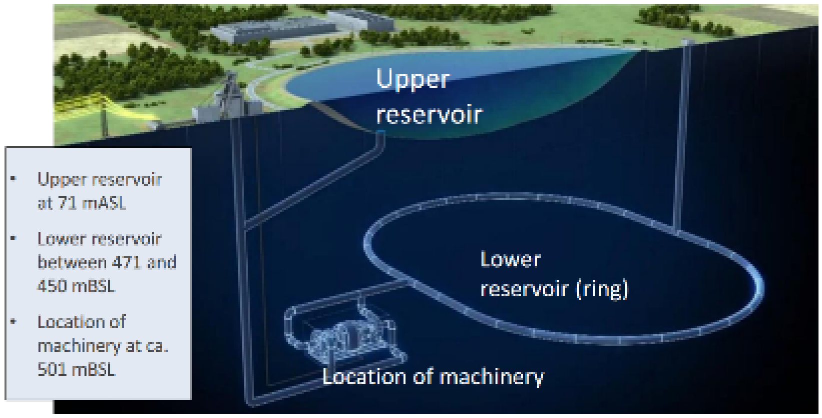


Figure 2-9. Illustration of underground mine PSH application. Source: image courtesy of Dr. André Niemann, University of Duisburg-Essen.

This section reviews the set of conditions used in prior research to evaluate the technical feasibility of underground PSH projects.

Operating condition of the mine

PSH projects require the mine to be safe for humans and equipment during the construction and operation stages. Continuous monitoring of the structural conditions of the mine is necessary for converting the mine into an underground facility. This implies that a mine needs to be operational and monitored at the point when the conversion work starts. Abandoned mines are often not suitable for underground pumped hydropower because their structural condition cannot be guaranteed.

Water hydraulic head and water flow

The length of the shaft water conveyance should provide enough elevation drop for the desired hydropotential energy. The hydraulic head can be approximated as distance from the ground level to the foot of the shaft, though actual head is a function of the difference in water surface elevations, minus any head losses. The water flow depends on the conveyance geometry and the volume of the reservoirs. The flow rate can be approximated by using the diameter of the shaft that serves as the waterway. The inner structure of the mine (Menéndez et al. 2019) or the presence of narrow passages between chambers (Kitsikoudis et al. 2020) can affect flow exchange. If ventilation shafts are not sufficiently present, the inflow and pumping could be restricted (Menéndez et al. 2020a).

It has been suggested in previous research in the United States that the preferred head for underground PSH is 1,200 m for a 2GW power plant (Allen et al. 1984). The range estimates from other research (Madlener and Specht 2020) indicate hydraulic head of 500–1,000 m and water mass of 0.1–1 million t for a range of capacity from 130 MW to 2.5 GW. Lower head values may also be appropriate given other technoeconomic conditions.

Seismic and geological stability

To be used for underground PSH, the mine and shaft have to be structurally stable and safe during the construction and operation stages (Sousa et al. 2022). Furthermore, the mine is required to be waterproofed along the entire underground surface area of shafts and tunnels. Most US underground mine rock formations were found to be naturally waterproof (Allen et al. 1984). In the absence of natural waterproofing conditions, a mine may have to be artificially sealed from the underground surface. Waterproofing could be required to prevent residual coal seams from getting in contact with water.

Repurposing of former mine land for pumped hydropower may require additional modeling of geological conditions of the mine. Certain geological conditions such as the presence of layers of sand may make the mine structurally unstable. Additional drilling may be required to more precisely evaluate the surrounding geological formation. Furthermore, continuous pumping and injection may inflict additional wear on the mine structures (Bodeux et al. 2017).

Repurposing and sealing

The tradeoff between the areas that can be used for PSH and the areas that have to be sealed necessitates technical and financial consideration. If parts of a mine cannot be waterproofed and repurposed for use in an underground scheme, those areas would have to be backfilled or sealed off. Sealing off parts of the mine would require using explosions and assessing water conditions and structural stability.

Caves and tunnels from other mines may be present in areas with intensive mining. If an active or an abandoned mine is located adjacent to the mine which is being repurposed, the caves and tunnels that approach the other mine would have to be sealed and are not suitable for further use (Wagner and Schauer 2019).

Generating equipment

From existing research and operational PSH, it is known that a plant can be fitted with reversible turbines of various types, depending on the head and flow rate (Morabito et al. 2020). Reversible Francis turbines could offer an economically effective operating solution for elevation of up to 750 m (Allen et al. 1984), and Pelton turbines could be used for mines of 750 m or larger (Madlener and Specht 2020). The width of a mine shaft can be a limiting factor on which equipment can fit to the lower levels of the mine and may require assembly of equipment once it has been taken to the machinery tunnel (Madlener and Specht 2020).

Existing infrastructure

There is little research dedicated specifically to ground infrastructure such as roads or transmission lines. While mines operate on electricity and usually have a transmission connection, as well as a road and a railroad, there is little research on the adequacy of that infrastructure. Most of the mentioned research includes the costs related to substation hardware and roads, but not to transmission expansion.

2.2.1.2 Financial characteristics

Technical and legal conditions dictate the required amount of investment and the investment duration. The large construction cost components include the following (Wagner and Schauer 2019, Witt et al. 2015, Hadjerioua et al. 2020):

- Upper reservoir groundwork, waterproofing
- Lower-level extension, sealing, groundwork
- Main shaft and waterway costs, tubes, water locks, ventilation system
- Transformers, generators, turbines, pump, network, communication
- Roads, transmission lines, substation equipment, upper-level infrastructure, security systems, landscape work
- Construction equipment, labor
- Insurance, financial interest

The main streams of revenue for underground PSH are similar to those for open pit pumped hydropower. Once revenue and costs are known, the existing metrics to quantify the direct financial effects of the project are benefit/cost ratio, LCOE, and NPV (Witt et al. 2015).

2.2.2 Geothermal Energy and Subsurface Thermal Energy Storage

2.2.2.1 Introduction

Geothermal systems are often spatially associated with ore deposits. In some cases, these systems were discovered while in search for epithermal mineral resources. Along with thermal energy storage, geothermal is considered one of the potential options for renewable energy development for current and former mine land. Both geothermal resources and thermal energy storage applications are considered in this report for potential deployment on mine land.

2.2.2.2 Geothermal resource applications for mine land

A wide range of potential applications exist for geothermal energy, mineral resources, and subsurface thermal energy storage that are relevant to mine land (Preene and Younger 2014, Patsa et al. 2015a, 2015b), as depicted in Figure 2-10. These consist of the following categories:

1. Power generation
2. Mineral extraction from geothermal brines
3. Process heating
4. Direct use for other mining operations
5. Direct use for non-mining operations (ground source heat pumps [GSHPs])
6. Subsurface thermal energy storage

These types of uses are more fully described in the following sections.

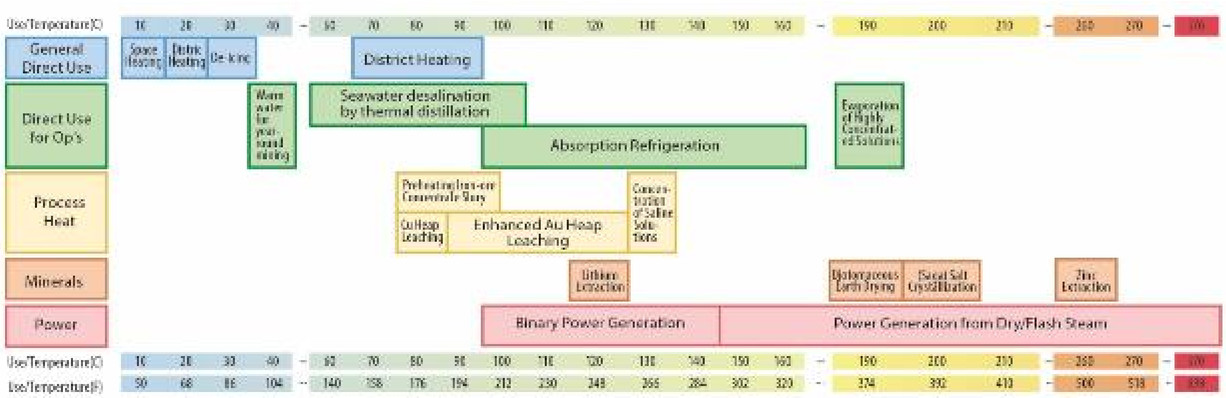


Figure 2-10. Variety of mining-specific uses of geothermal resources as a function of temperature and applications (modified after Patsa et al. 2015b).

Power generation

Developing on-site power generation capabilities or building transmission lines is a common requirement for many of these mines, resulting in expensive energy costs. For example, Reyes et al. (2011) proposed three geothermal projects with potential capacity from 75 to 450 MWe based on a reservoir temperature of 230°C–300°C and an assumption power density of 10 MWe per km^2. There are at least two documented cases of geothermal power generation at active mines. The most well-known case is the Lihir

Au mine in Papua New Guinea, which has been described (Simmons and Brown 2006, White et al. 2010, Maennling and Toledano 2018, Cooke et al. 2020). The geothermal system was first put online in 2003 and currently produces 56 MW, delivering power to the mine and the neighboring community (Maennling and Toledano 2018).

A geothermal demonstration project was conducted at the Florida Canyon mine in Nevada (Hastings et al. 1988), where coproduced 110°C geothermal fluids were used to power a 65 kW organic Rankine cycle unit (Clark 2014). The ElectroTherm Green Machine organic Rankine cycle unit was in operation between 2013 and 2014. It experienced some operational issues with scaling and irregular supplies of hot water to power the system, but the unit demonstrated the feasibility of local power generation using geothermal mine water. There are two additional mining projects underway in Indonesia (the Onto porphyry Cu-Au deposit on Sumbawa and the Toka Tindung Au mine in North Sulawesi) that have associated geothermal resources that are being evaluated for their development potential.

Mineral extraction from geothermal brines

Geothermal brines have long been recognized for containing dissolved minerals that could potentially be extracted (e.g., McKibben et al. 1988, Gallup 1998, Brown and Simmons 2003, Bourcier et al. 2005, Bloomquist 2006, Neupane and Wendt 2017, Simmons et al. 2018). A Zn recovery plant was in operation for a short time at the Salton Sea geothermal field (Clutter 2000). A concerted effort focuses on directly extract Li from geothermal brines (Figure 2-11) at the Salton Sea and other brines that contain elevated Li concentrations (e.g., Paranthaman et al. 2017, Stringfellow and Dobson 2021, Sanjuan et al. 2022). Berkshire Hathaway Energy Renewables commissioned in June 2022 a pilot facility to extract LiCl from their geothermal brine, and EnergySource Minerals is scheduled to start construction on a commercial-scale $LiOH \cdot H_2O$ facility that would commence operations in 2024. Controlled Thermal Resources is also planning on developing an integrated geothermal power facility with direct Li recovery from produced geothermal brines; this facility is also planned for 2024. Other pilot-scale mineral recovery efforts from geothermal brines involve SiO_2 (e.g., Lea and O'Sullivan 2020, Climo et al. 2021). These mineral recovery operations could provide ancillary benefits to a geothermal power facility, thus improving the overall economics of a hybrid project.

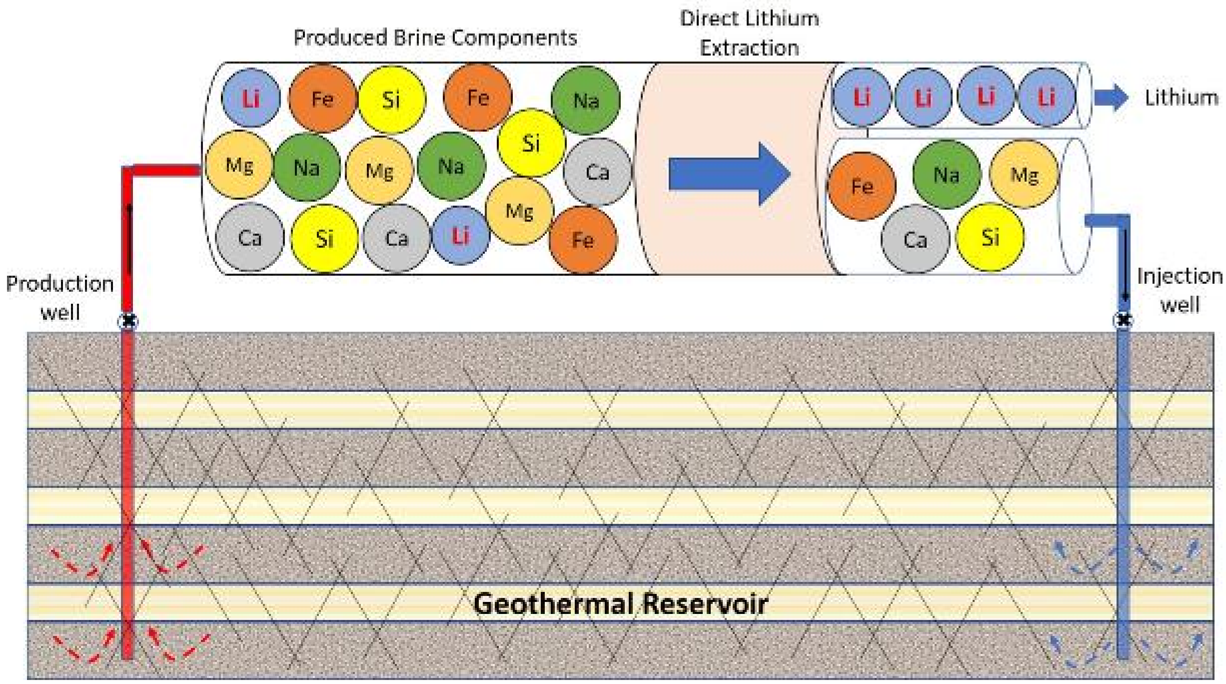


Figure 2-11. Conceptual model for direct Li extraction from geothermal brines (graphical abstract for Stringfellow and Dobson 2021).

Process heating

For mines in areas with high geothermal potential, geothermal energy can be used for some of a mining operation's electrical power needs. Hot fluids can be used directly in applications such as raffinate heating in Cu production and enhanced heap leaching for the extraction of Au and Ag (Patsa et al. 2015a). A study in Chile indicated that using 70°C geofluid as the primary heat source in a geothermally-enhanced heap leaching alternative would increase production levels by an average of 1.2% per 1°C change in the raffinate temperature. The resulting fuel-cost savings for the proposed system upgrade corresponded to a 12 month projected payback period.

Direct use for other mining operations

Most operating mines have on-site space heating or cooling needs (e.g., within administrative buildings or live-in camps). Based on a study involving 12 mines in Canada, a switch from traditional heating and cooling to very low-temperature GSHPs could result in total annual heat savings of 20,915 kWh, equivalent to C$1.5 million/year in cost reductions and 18,850 t in CO_2 emission reductions (Patsa et al. 2015a). Underground mines in areas of high geothermal potential must deal with higher ventilation loads; these loads can be partially handled by in-situ geothermal power generation (Patsa et al. 2015a). Patsa et al. (2015a) further reports of a new geofluids plant in Argentina that would cover 66%–100% of operational needs of the mine. This plant will save up to 19–30 million L of fuel annually reduce GHG emissions by 53,000–93,000 MT.

In Poland, geothermal mine water heating systems have been implemented for mine offices, which have an output of 135 kW, and mine bathhouses with an output of 20 kW. (Walls et al. 2021, Chudy 2022). These systems both have open heat pump systems with surface discharge. Another system was set up in a Mo mine in Colorado to provide heating in mining shafts (Jensen 1983). Its main goal was to keep the shafts warm enough for extraction operations.

Direct use for non-mining operations (ground source heat pumps)

Social license is an integral part of any mine's sustainable development plan. That license includes the importance of the operator's in-house green energy culture and policy and the option for local communities to use the energy that is produced. In the postclosure phase, hot water irrigation can enhance reclamation rates, or geothermal district heating can support job creation. An opportunity for social license is to use engineered features associated with mine sites, where the capital and operational costs are already committed, to exploit heat energy from geothermal sources.

Areas near abandoned mining operations may have access to low-enthalpy heating sources and water from flooded mine sites to offset or replace costs from conventional heating sources. Motivation for installing GHPs may come from financial savings, environmental benefits, reduction in carbon footprint, and gaining economic benefits from closed mining systems. Several review papers summarize existing projects and discuss the benefits and challenges of this direct use of mining water (Peralta Ramos et al. 2015, Preene and Younger 2014, Walls et al. 2021, Hall et al. 2011, Chu et al. 2021). These mine water geothermal (MWG) systems require an initial investment (capital costs) of designing and emplacing a geothermal system, and these costs must be offset by the long-term operational cost savings of the geothermal system. Cost savings come from the lower maintenance cost, decreasing the need to import fuel, and the ability to use existing infrastructure that remains from previous or existing mining operations. MWG, in comparison to other GHP systems, can benefit from constant temperature and the availability of water for recirculation. The use of mine water for heating can represent a sustainable use of current and former mine land and support economic development in locations previously supported by mining activities.

Several projects have been documented since the early 1980s in Europe, Canada, and the United States in which geothermal systems have been used for heating and/or cooling in buildings, homes, and pools and other recreational areas (Preene and Younger 2014, Peralta Ramos et al. 2015, Jessop et al. 1995). These systems used a wide variety of open- and closed-loop GHPs. Figure 2-12 (Walls et al. 2021) shows conceptual schematics of the two systems as well as a third type, which uses gravity drainage from the mine, a common practice in the United Kingdom. This third type can provide cost savings by not having to drill a well and install a pump. However, no existing systems using this type of drainage have been reported (Younger and Loredo 2008, Walls et al. 2021). The design and benefits of the potential geothermal system will be dependent on the site location and proximity to the area of need. Open-loop systems extract groundwater, which passes through a heat transfer system and is either reinjected into the source reservoir or disposed of as surface water (either to a waste treatment system or to the environment). Closed-loop systems do not extract water because they have a piping system where a fluid is circulated in contact with the reservoir, and the heat transfer system interacts with the circulating fluid.

Important factors determining the feasibility of a GHP system include the temperature of the water and the size of the reservoir. The heat of the reservoir may be hot or cold enough to provide direct heating or cooling, but in most cases, the temperature is more moderate, and a heat pump is used to either extract or deliver heat to the water. In both cases, the temperature of the water may be changed by the MWG over time, which may cause environmental effects or affect the efficiency of the geothermal system.

Given the large number of potential abandoned mining sites, criteria are needed to identify potential sites for developing the direct use of the sites for a local area's heating and cooling. Initial screening should investigate the mine's proximity to an end user, water flooding status, and water temperature (Farr et al. 2016, Farr and Busby 2021, Hall et al. 2011, Díaz-Noriega et al. 2020). Other factors could be the local climate, the distance from and access to power distribution and the transmission network, the price of purchasing and transporting alternate energy sources, the size and type of the geothermal resource in terms of production enthalpy, achievable mass flow rates, and brine mineral content (Díaz-Noriega et al.

2020, Younger and Loredo 2008). Farr and Busby (2021) noted that MWGs would be appropriate sites that lack competition for the water resource owing to their low water quality, natural porosity or other supporting hydrogeological properties, and sufficient depth and water content. Several papers focus on summarizing factors for selecting sites based on location, the amount of water, and water temperature. Other factors to consider are the existence of access points and historical knowledge of the site.

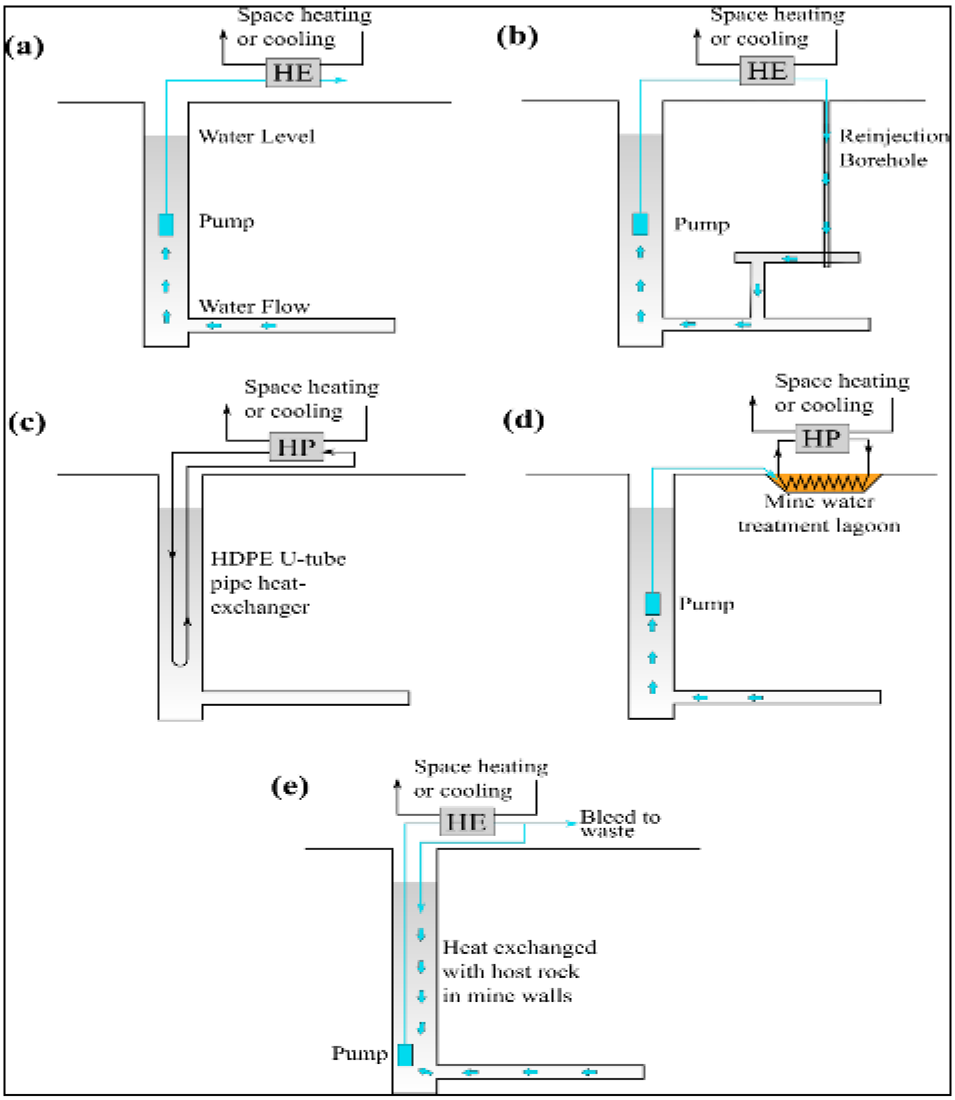


Figure 2-12. Configurations of different MWG energy systems: (a) open system with discharge; (b) open system with reinjection; (c) borehole closed loop; (d) surface closed loop; (e) standing column. HDPE is high-density polyethylene. From Walls et al. 2021. Copyright 2016 David Banks. HE = heat exchanger. HP = heat pump.

For the mine land, the available infrastructure can be a major advantage, which can include bore holes, roads, pumps, and monitoring wells. Because the flooded mines are anthropogenically created aquifers, current and former mine land will have remnant void space that will change over time owing to settling and tectonic activity. The type of previous mining operation will also affect the void space remaining. For example, for coal mining, room and pillar mines (older method) retains more void space (50%) than long wall mining (void space 20%) (Andrews et al. 2020). As such, all flooded mines will have different sizes and connectivity, and studies on how pumping for geothermal use will affect the temperature of the minefield is important. A development of a 3D model of the mine structure may be required to understand how water will flow through the system (Farr and Busby 2021). Additionally, in an open-loop system, the effect of the return water temperature on the intake temperature over time needs to be considered, including whether circulation in the mine is sufficient to avoid stratification (Liu et al. 2016, Farr and Busby 2021).

Water chemistry is also a factor to consider. Many existing projects have reported substantial problems with Fe levels—even 1 mg/L of Fe can cause problems with clogging and may require keeping systems under positive pressure, limiting dissolution of oxygen, or installing closed-loop systems (Farr et al. 2016, Hall et al. 2011, Korb 2012, Peralta Ramos et al. 2015, Rodriguez and Diaz 2009). A screening criterion focused on Pennsylvania, West Virginia, and Ohio has been developed by Watzlaf and Ackman (2006, 2007) which may be useful for identifying potential projects. The tool includes identifying flooding mine locations, legal concerns, water quality concerns, and geology.

Researchers at Ohio University have developed a tool for identifying mines suitable for MWG in southeastern Ohio (Richardson 2014, Richardson et al. 2016, Madera-Martorell 2020). Using GIS software, they identified flooded mines within 1.6 km of a population area. Once locations were identified, the mines were further characterized by the effective mine water volume, groundwater velocities, flow direction, and recharge rates. Using this information and the temperature of the mine water, the researchers calculate the total amount of extractable heat from the mass and heat capacity of the water and the temperature change. From this analysis, researchers identified 147 mine sites in Ohio, 129 of which are already flooded, as possible sites for direct heating use. The average heat available for these sites was between 0.55 and 2×10^9 kJ/year, with a maximum value estimated at up to 45×10^9 kJ/year. Most of the mines were coal mines, but limestone, gypsum, and clay mines were also identified as candidates. Once sites were identified, further detailed analysis was necessary to understand the hydrology, water chemistry, and accessibility of the mine. Additionally, in Madera-Martorell (2020), methods are described for modeling potential heat extraction with information gained from historical maps and samples from nearby water wells. These approaches could be broadly applied to mine sites in other areas to identify candidates for development. A similar approach has been developed to assess the MWG potential of abandoned mines in Quebec and Nova Scotia, Canada (Arkay 2000).

Subsurface thermal energy storage

Current and former mine land may also be used for thermal energy storage when above ambient water is pumped into the well. This may occur in tandem with heating and cooling systems. The HEATSTORE pilot project is currently underway in Bochum, Germany which combines the two systems, also incorporating solar energy collection to improve efficiency (Hahn et al. 2019, 2021, 2022, Hamm et al. 2021). The project is described in more detail in Section 2.2.2.3.

To understand and predict geothermal system performances, efforts have been made to develop numerical models for those systems. To support the development of geothermal from current and former mine land in the United Kingdom, the Glasgow Geothermal Energy Research center was created to collect data and supporting information for expanding MWG (Adams et al. 2019, Monaghan et al. 2022). The HEATSTORE project in Bochum, Germany, is under development to demonstrate the use of an abandoned mine to store heat and to provide heating and cooling to nearby buildings. Efforts in modeling potential projects, including estimating energy storage and production, heat flow in subsurface mines, and specific site readiness for geothermal, have been published to support the development of current and former mine land projects worldwide (Bao et al. 2019, Chudy et al. 2022, Diaz et al. 2014, Farr et al. 2016, Frejowski et al. 2021, Perez Silva et al. 2022).

2.2.2.3 Selected case studies

The case studies presented here are focused on direct-use or process heating (GSHP), since they are the most common geothermal applications on mine land. Table 2-8 is a more complete summary of world-wide direct-use current and former mine land projects.

Table 2-8. Summary of worldwide direct-use current and former mine land projects

Mine	Year started	Mine type	Location	Extracted depth (m)	Temperature (°C)	End user	Heating power	Reference
Springhill	1989	Coal	Nova Scotia, Canada	140	18	Several projects and building types	1.5 MW	Jessop et al. 1995, Walls et al. 2021, Preene and Younger 2014, Chu et al. 2021
Goyer Quarry	2006	Aggregate	Quebec, Canada	—	—	36 apartments using heat pumps	3.6–5.3 kW/site	Ramos and Falcone 2013, Raymond et al. 2008
Vancouver Island University	2018	Coal	British Columbia, Canada	135–180	—	University buildings	—	Wilson 2018
Heerlen	2003	Coal	Netherlands	700	16–28	Office buildings/ university/ homes	700 kW	Verhoeven et al. 2014, Adams et al. 2019, Roijen et al. 2007
Hunosa/Mieres Asturias	—	Coal	Spain	362	17–23	University and hospital	160 MW	Lara et al. 2017, Walls et al. 2021, Menéndez et al. 2020b Oppelt et al. 2021, 2022
Alsdorf	—	Coal	Germany	890	15–26	Office buildings	—	Ramos and Falcone 2013
Bad Schlema	—	—	Germany	—	—	School building	504.7 KWh/m²	Ramos and Falcone 2013
Zeche Robert Muser/Bochum	—	Coal	Germany	—	—	Schools	0.690 kW	Oppelt et al. 2021, 2022
Tagebau Hamback/ Bergheim	—	Coal	Germany	—	—	Several buildings	0.620 kW	Oppelt et al. 2021, 2022
Seinkohlerevier/ Bergheim	—	Coal	Germany	—	—	University/ hospital		Oppelt et al. 2021, 2022
Ehrenfriedesdorf	1994	Sn	Germany	—	—	Museum; high school	82 kW	Ramos and Falcone 2013, Oppelt et al. 2022, Wieber and Pohl 2008, Preene and Younger 2014
Freiberg	2009	Ag	Germany	60	10.2	Castle	Heating 160–180 kW; cooling 120 kW	Ramos and Falcone 2013, Chu et al. 2021
Freiberg	—	—	Germany	—	—	University/ hospital		Ramos and Falcone 2013, Oppelt et al. 2021, 2022
Wismut-Schacht 302, Marienberg	2007	Uranium	Germany	144	12.4	2 commercial buildings, athletic center	690 kW	Ramos and Falcone 2013, Oppelt et al. 2021, 2022, Wieber and Pohl 2008, Matthes and Schreyer 2007
Wettelrode	2013	—	Germany	283	13	Mining museum	47 kW	Ramos and Falcone 2013, Chu et al. 2021
Heinrich	1984	Coal	Heisingen, Essen, Germany	—	—	Nursing home	350 kW	Preene and Younger 2014, Chu et al. 2021
Kongsberg	2005	Ag	Norway	250	—	Festsalen (concert hall/cavern)	12 kW	Walls et al. 2021, Banks et al. 2019, Preene and Younger 2014
Folldal	1998	Cu-Zn-S	Norway	600	6	Wormshall (cavern) used	18 kW	Walls et al. 2021, Banks et al. 2019, Preene and Younger 2014

Mine	Year started	Mine type	Location	Extracted depth (m)	Temperature (°C)	End user	Heating power	Reference
						for concerts and banquets		
Bridgend Council in Wales	—	—	UK	—	—	150 homes	—	Farr et al. 2016
Egremont	—	—	UK	256	—	Test case	100 kW	Ramos and Falcone 2013
Crynant	—	—	UK	64	—	Large farmhouse, farm workshops, adjacent building	35 kW	Walls et al. 2021
Nest Road	—	Coal	UK	130	—	Beverage warehouse	1.2 MW	Walls et al. 2021
Abbotsford Road	—	Coal	UK	110	—	Beverage warehouse	2.4 MW	Walls et al. 2021
Dawdon	—	Coal	UK	—	—	Treatment facility building, upgrading to housing	Will upgrade to 6 MW	Walls et al. 2021
Caphouse	—	Coal	UK	—	—	Nearby museum heating	10 kW	Walls et al. 2021
Markham Colliery	—	Coal	UK	170	13.5	Small office complex, preheating gas engines	—	Al-Habaibeh et al. 2018
Shettleson	1999	Coal	UK	100	12	Buildings (16 homes)	65 kW	Walls et al. 2021, Banks et al. 2003, Preene and Younger 2014
Lumphinnans	2000	Coal	UK	173	15	Buildings (18 homes)	65 kW	Walls et al. 2021, Banks et al. 2003, Preene and Younger 2014
Glasgow Observatory	—	Coal	Scotland, UK	—	—	Observatory for storage research and mine water heat		Monaghan et al. 2022
Fortissat	—	Coal	Scotland, UK	—	18	Houses and private homes	3 design options A. 700 kW B. 1 MW C. 2 MW	Harnmeijer et al. 2017
Bytom/CZOK/ Sobieski Mine	—	—	Poland	200–500	13–15	CZOK offices, mine bath houses	10–60 kW	Walls et al. 2021; Chudy 2022
Novoshkhtinsk, Rostov	2009	Coal	Russia	390	18–23	Hospitals, schools	10.9 kW	Oppelt et al. 2022, Walls et al. 2021, Ramos et al. 2015, Preene and Younger 2014
Hachov-Plana/Marienbad	—	Uranium	Germany	—	—	University	0.55 kW	Matthes and Schreyer 2007, Oppelt et al. 2021, 2022
Rozna Mine	—	Uranium	Czech Republic	—	—	Theoretical case study using mine water to heat the municipality of Dolni Rozinka; 3 options analyzed	To supply an annual consumption of 4,350 Gj	Walls et al. 2021, Vokurka and Kunz 2022
Jeremenko mine	—	—	Czech Republic	—	26–29	Admin buildings and employee baths	91 kW	Walls et al. 2021
Svornost	—	—	Czech Republic	—	29–36	—	—	Walls et al. 2021

Mine	Year started	Mine type	Location	Extracted depth (m)	Temperature (°C)	End user	Heating power	Reference
Mount Wellington Mine	—	Sn	Cornwall, UK	—	—	Kensa Engineering factory and offices	20 kW	Preene and Younger 2014
Tazareh and Gheshlagh mines	—	Coal	Iran	—	—	Alborz-Sharghi coal washing plant	—	Shokri et al. 2016
Zhang-shuanglou	—	Coal	Zuxhou City, China	—	—	Several buildings	4,750 kW	Oppelt et al. 2021, 2022, Guo et al. 2017

Europe

Asturias, Spain

A geothermal mine water district heating project is located in the Asturias coal district of northwestern Spain, where boreholes have been drilled into the abandoned coal mine workings of the Barredo Colliery and are used for the district's heating system (Figure 2-13) in the town of Mieres. The system has an installed capacity of 2.2 MWt, supplying heat to 2 public buildings and 245 dwellings, and has an annual thermal energy output of 2,462.88 MWh (Jardon 2013, HUNOSA 2019). The system provides radiant heat to some buildings and is combined with heat pumps and gas-powered boilers to provide higher-temperature water for domestic hot water needs. The estimated GHG emissions reduction when compared with using only NG heating is 653.27 MT CO_2/year. (Lara et al. 2017). Using water for heating provides an economic benefit to the mining company and to the hospital and university that use the system for heating and cooling. One key aspect for successful deployment of this system was working with the mining company during closure to develop MWG potential. The volume of the mine system is 11 Mm^3 and maintains temperatures of approximately 20°C year-round. Because of the elevated hardness of the water, a closed-loop system was installed, and a heat pump was installed to allow the system to operate at optimal conditions. In 1 year (2015), a total of 7.6 MW of both cold and heat energy was supplied, costing 1.32 MWh of electrical energy. This resulted in an 80% reduction of CO_2 emissions and 10% cost savings (Lara et al. 2017, Walls et al. 2021, Menéndez et al. 2019, Oppelt et al. 2021). Based on the success of this project, another district heating project that would use the nearby Fondón Colliery is currently under consideration.

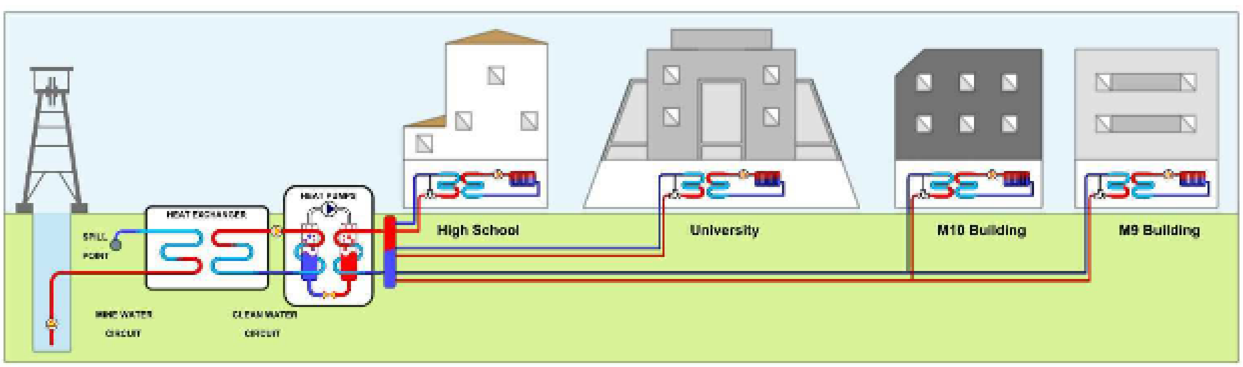


Figure 2-13. Schematic depiction of Barredo district heating system, Spain. This is a closed-loop system that provides heat and cooling to multiple buildings. The closed-loop system was designed to avoid problems with poor water quality (HUNOSA 2019).

Heerlen, Netherlands

A well-established network in Heerlen, Netherlands (Verhoeven et al. 2014, Adams et al. 2019, Roijin et al. 2007, Bazargan Sabet et al. 2008) encompasses a system of heat pumps extracting water from an abandoned coal mine that services several office buildings, a university, and some homes. This system is considered to be the world's largest current and former mine land geothermal system. The system, which has a heating power of 700 kW, uses water that ranges from 16°C to 28°C, is pumped in an open-loop system with reinjection, and powers office buildings and homes. The heating area is reported to be 123,000 m^3. A hybrid network has been developed in the last stage of the project, in which the residual (unused) heating and cooling capacity from one customer is used for other customers. Because of its success, it has been receiving investment through national and European subsidies. A thermal smart grid is planned into the future to recognize patterns of demand over time, making the system more efficient.

Bochum, Germany

As part of the HEATSTORE project, a mine thermal energy storage pilot plant (concept shown in Figure 2-14) has been developed in Bochum to reuse abandoned colliery at a depth about 75 m below the surface and store water heated by a concentrated solar system during the summer months (Hahn et al. 2019, 2021, 2022, Hamm et al. 2021). The heated water will be retrieved for a neighboring district heating system during the wintertime. Three boreholes were drilled into existing open mine voids. Based on the coal production amount (to calculate the void volume) and an assumption of 10% subsidence, and a 50°C mine water temperature difference, the heat capacity is calculated to be approximately 165 MWh. Based on the pre-investigation of the project, Hahn et al. (2022) provided recommendations for preferred hydrogeological conditions, including using non-backfilled drift with full saturation; avoiding a steady-state hydraulic gradient; aiming for a slow water table drawdown rate; avoiding hydraulic connections (thermal shortcut) between mine thermal storage and reinfiltration well after thermal use and planning for countermeasures for scaling issues by first performing precipitation calculations to understand its severity. The HEATSTORE project provided detailed technical recommendations for engineering design. They proposed to monitor site subsidence, groundwater levels, and the heat plume. Using pressure or temperature sensors and fiber optic cable, which can provide continuous temperature data along the cable, this monitoring network can provide data to calibrate numerical models, which then can be used for system performance prediction.

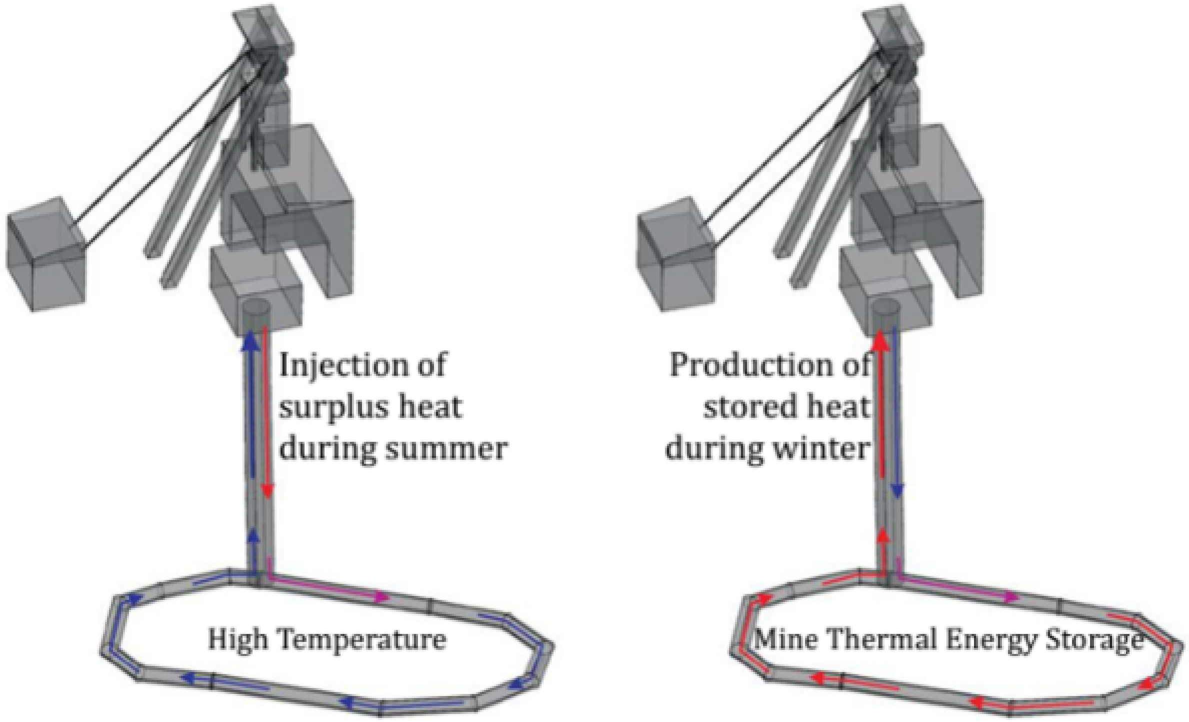


Figure 2-14. Conceptual model of the mine thermal energy storage project in Bochum. This open-loop pilot project is coupled with a high-capacity condensed solar array and aims to improve the efficiency and design of MWG systems (Hahn et al. 2019).

Other pilot systems in Europe include approximately 10 active systems in the United Kingdom, a few small systems associated with caverns in Norway, and approximately 12 active systems in Germany (Bracke and Bussmann 2015, Peralta Ramos et al. 2015, Hall et al. 2011, Walls et al. 2021). One more recent installation for a winery in the United Kingdom (Lanchester Wines) is a good case study exemplifying the challenges faced when installing MWG systems (Banks et al. 2022, IEA 2021).

Canada

Springhill, Nova Scotia

In Canada, a successful and long-term active system in Springhill, Nova Scotia has been operating since late 1980 (Jessop et al. 1995). This site is located over an abandoned coal mine with water temperatures averaging 18°C and generates up to 111 kW heating and 160 kW of cooling power. It is an open system with reinjection into the groundwater. The users are several industrial buildings with a total area of 14,000 m^3. The data from the first year shows that the heating cost of the system was approximately C$18 thousand per year, which is less than the annual heating cost of the original building (Jessop et al. 1995). In addition to economic benefits, Jessop et al. (1995) also calculated the avoided CO_2 emissions to be about 370 t/year compared with a geothermal heating option and 780 t/year compared with oil heating and conventional air conditioning. Another project in the Goyer Quarry located in Quebec uses a flooded and abandoned mine to provide heating and cooling to an apartment complex. This project was designed to be decentralized, with heat pumps at each apartment. The capacity of this system is estimated at 3–6 kW (Peralta Ramos et al. 2015, Raymond et al. 2008). Despite the success of these projects, other projects in Canada have been slow to start. Currently, few projects are proposed in Quebec (Raymond et al. 2008), and a new system is currently being installed in Vancouver Island (Jessop et al. 1995, Walls et al. 2021, Banks et al. 2003, Bracke and Bussmann 2015, Alvarado 2022). Notably, several active mines in Canada use geothermal energy for on-site operations, which potentially could be converted to community use during post-closure (Chu et al. 2021).

United States

Table 2-9 contains a list of known current and former mine land projects in the United States. A few of them are presented here as case studies.

Montana Tech

At Montana Tech University in Butte, Montana, a current and former mine land geothermal system was designed to heat and cool Montana Tech's Natural Resources Building (Blackketter et al. 2015, Hagan 2015, Malhotra et al. 2014). This closed-loop GSHP was designed to supply space heating and cooling needs for a 5,200 m^2 building, reducing their reliance on NG heating and lowering the building's carbon footprint. This system was designed as a pilot program and funded by the American Recovery and Reinvestment Act, which included extensive student projects and monitoring, generating usable information on design and performance for future studies. A performance analysis based on half a year's operation (January to July 2014) indicated the system was able to deliver 88% of the building's heating and cooling needs. The system demonstrated a reduction in CO_2 emissions of 39% and annual savings of $17 thousand in utility costs when compared with a baseline NG system (Blackketter et al. 2015). However, because of some leaking in piping, personnel turnover, and loss of institutional knowledge, the system has been nonfunctional for several years.

Park Hills, Missouri

Park Hills, Missouri, generates 113 kW of thermal energy for an 8,100 ft^2 (750 m^2) city office building and has been operational since 1996 (Watzlaf and Ackman 2006, 2007; Banks et al. 2003, Bracke and Bussmann 2015). This GSHP open-loop system was built on an abandoned Pb mine. Water averaging 14°C is drawn from a 120 m well in an open-loop system, providing 113 kW of energy. Reports on this system estimate the cost for installation was $132,400 with a payback period of 4.6 years.

Michigan Tech

In the abandoned Quincy Cu mine in Calumet, Michigan, a demonstration project was installed for heating a 15,000 ft^2 building (Bao et al. 2019). The project provided information on the actual use and economic value of this energy source. It was reported that the system would produce 10.26 MW of thermal energy for the Keweenaw Research Center from a 91 m depth using 12.8°C mine water; the actual amount of thermal energy being used depends on the mine water temperature and the pumped flow rate, which can vary seasonally as heating needs change (Bao et al. 2019). Bao et al. (2019) compared the heating cost when using this system to other heating methods for the Upper Peninsula of Michigan and concluded the cost is just above the heating from burning natural gas but much lower than the cost directly from electric heating or heating oil or propane (see Table 2 from Bao et al. 2019). The estimated installation cost of this system was $100,000 with a payback period of 3–5 years, and the system has an estimated lifetime of 20–25 years (Bao et al. 2019, 2020). The system is still running.

Pennsylvania

Historically, several geothermal projects using mine water in Pennsylvania have been reported (Korb 2012), of which only one is still operational (Walls et al. 2021) at Marywood University. This project was used to heat a university building using mine water drawn from a depth of 122 m, which had a temperature range of 14°C–16°C. Other projects in this area reported problems with oxidation of Fe in the produced water, creating clogging issues with the pipes.

Table 2-9. Known current and former mine land projects in the United States

Mine	Year started	Mine type	Location	Extracted depth (m)	Temp. (°C)	End user	Heating power	Reference
Henderson	1980	Molybdenum	Empire, CO		29	Direct heating of mine ventilation/ prevent icing of shafts	0.79– 4.1 MW	Preene and Younger 2014, Jensen 1983, Chu et al. 2021
Quincy	2009	Copper	Michigan	91 m	13	SWHP/use of mine water to heat a 15,000 ft^2 building/82,000 households	129 MW	Bao et al. 2019
Kingston	1981	Coal	Pennsylvania	58 m		Recreation center	100 kW	Korb 2012, Chu et al. 2021
Pittsburg	2008	Coal	Pennsylvania			Church/senior living		Korb 2012
Park Hills	1995	Lead	Missouri	120	13.9	City building	113 kW	Walls et al. 2021, Watzalf and Ackman 2006, Preene and Younger 2014
Butte, Montana	2013	Coal	Montana	245	25	5,200 ft^2 natural resources building/ heating and cooling		Blackketter 2015, Hagan 2015, Malhotra et al. 2014, Oppelt et al. 2022, Liu et al. 2016
Scranton	2010	Coal	Pennsylvania	122	16.1	University building (Marywood University)		Korb 2012
Kingston	1979	Coal	Pennsylvania			Radio Shack store		Korb 2012
Kingston	1980s–2000	Coal	Pennsylvania			Hospital		Korb 2012
Carbondale	1980–1990	Coal	Pennsylvania			Small business		Korb 2012

2.2.2.4 Key lessons learned

The case studies from the literature provide several key lessons that should be considered when developing MWG systems.

- Permitting takes time. It is important to understand the legal issues and start planning early. Demanding regulatory challenges may exist (Banks et al. 2022).

- Understanding mine water chemistry is important to determine what further preventive actions or measurements need to be taken (Hahn et al. 2022). Data collection, including test holes and basic chemistry, is vital (Banks et al. 2022). Preventing oxidation of Fe, which is the main issue, can be done through proper design (Hahn et al. 2022). Clogging or scaling is common, as well as aggressive mine water chemistry (Banks et al. 2022, Althresh 2016). Systems that were unsuccessful or eventually abandoned often had problems with pipes clogging or leaking pipes, which affected water flow and efficiency. Water should be of good quality, or systems should be built to manage water quality issues (Banks et al. 2022).

- Water table drawdown should be monitored. Hahn et al. (2022) stated that a slow rate of drawdown is preferred and discussed the ways to achieve it. Preene and Younger (2014) concluded long-term extraction from an open system could result in a change in groundwater levels and, therefore, ecological issues and potential ground deformation. The HEATSOURCE project has integrated sensors to monitor both seismic and ground deformation potentially caused by pumping of the mine water (Hahn et al. 2019, 2021, 2022).

- A reliable source of constant temperature water is needed. The temperature differential between the surface heat source and the downhole injection temperatures should be at least 10°C–15°C (Hahn et al. 2022). Pumping rates should maximize efficiency by optimizing water temperatures and flow rate to meet peak load conditions and operation within the pump manufacturer–specified ranges (Malhotra and Liu 2014). Inefficiencies in pump and distribution design can negatively affect the economics of the system (Liu et al. 2016). Additionally, thermal stratification in the well owing to poor circulation will affect system performance (Blackketter et al. 2015, Thornton and Blackketter 2014).

- Thorough hydrological-thermal and geochemical modeling studies are beneficial to identify technical issues, predict the economic viability of the project, and reduce operational risks (Preene and Younger 2014).

- Older mine systems may have altered subsurface structure owing to settling after closure. It may take more than one borehole to find mine voids (Banks et al. 2022). Production wells need to be drilled directly into mine voids, not into back-filled areas. (Hahn et al. 2022).

- It is important that experienced consultants with knowledge of hydrogeology and geothermal systems are involved (Banks et al. 2022).

- A long-term sustainability plan is important. Ongoing maintenance should be expected, including unclogging filters and flushing of pipelines. The operational plan should include personnel turnover and training as well as ongoing maintenance costs (Blackketter et al. 2015). Designs that necessitate frequent maintenance were unsustainable after the initial pilot phase because of the loss of funding or expert or institutional knowledge about the system (Blackketter et al. 2015, Lee 2014, Banks et al. 2022).

- The HEATSTORE project (Hahn et al. 2021, 2022, Hamm et al. 2021) concluded that the thermal hydrogeological condition of the mine is a key component for determining efficiencies. Additionally, monitoring temperatures and pressures using sensors or continuous fiber optic cables will provide data to calibrate numerical models that will be used for system performance prediction.

2.2.2.5 Barriers to deployment

Many challenges are faced when implementing these systems. Challenges may include finding source funding, obtaining permissions from applicable regulatory agencies, the need for extensive site-specific engineering design, economic modeling of potential benefits, management of water chemistry, licensing and permitting, and the long-term sustainability of the system. Maennling and Toledano (2018) categorized roadblocks to success into five categories: technical, available expertise, financing, regulatory, and local interest. Walls et al. (2021) used similar criteria when summarizing some of the challenges with implementing MWG systems into four categories: planning, construction, operational, and economic (Figure 2-15). Additionally, Farr and Busby (2021) indicated that two barriers to consider are ownership of the site and water rights, which may be difficult to define in terms of current and former mine land and geothermal.

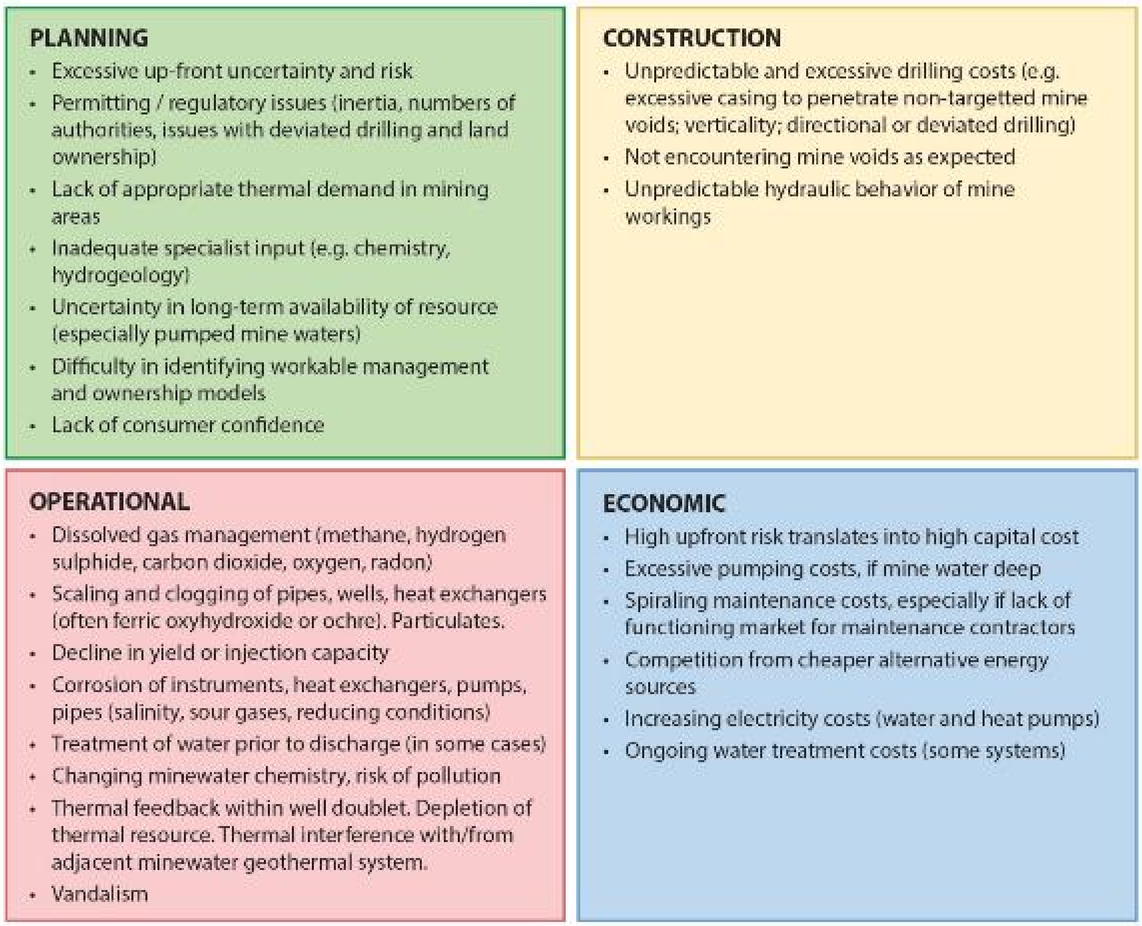


Figure 2-15. Summary of challenges in MWG systems, separated into four major categories. Not all challenges will apply to all projects (Walls et al. 2021).

2.2.2.6 Drivers for deployment

Several factors have been identified for determining if geothermal energy may be a viable target for development in an existing mine land. Drivers can include a desire for continuing to use mining operations infrastructure in a community that has important historical, heritage, and cultural ties to mining. Other drivers are the remoteness of the community, which affects the ability to allow the mine to generate energy locally without supply chain hurdles. Water production systems may be already available; for example, water already pumped from the ground for treatment or to limit flooding can also be used for heating or cooling (e.g., Farr et al. 2016, Madera-Martorell 2020). Other drivers may be job creation, lower operational costs, and a desire to develop low-carbon energy sources (Chu et al. 2021). The Springhill project in Nova Scotia, Canada, saw considerable economic benefits and also indicated that the workers saw increased benefits owing to the addition of cooling in the summer and overall cleaner working conditions (Jessop et al. 1995). It has been proposed that incorporating the development of direct-use geothermal and other project types should be part of the mine life cycle. Direct-use geothermal was a key factor in the success of the system in Asturias, Spain (Menéndez et al. 2019, 2020b, 2022; Loredo et al. 2011, HUNOSA 2019). Systems can be developed to offset the energy costs of existing mine operations while the mines are active. The heating systems used for mining operations can then be transferred to the surrounding communities post-closure (Bracke and Bussmann 2015, Patsa et al. 2015a, 2015b, Rodriguez and Diaz 2009, Chu et al. 2021).

2.2.3 Compressed Air Energy Storage

2.2.3.1 Introduction

There are three types of CAES systems. In diabatic CAES systems, heat generated during compression is dissipated as waste, and thermal energy must be added during air expansion in the energy recovery phase. In adiabatic CAES (A-CAES) systems, heat generated during compression is stored for later use in air expansion for energy recovery. In isothermal CAES systems, the temperature of the air during compression and recovery expansion processes is maintained more or less constant.

The growing interest in intermittent renewable energy sources along with the availability of abandoned mines have motivated numerous studies of the technical feasibility of developing CAES in unused mine openings. To date, no excavated mine has been used for commercial CAES, despite the fact that the only two operating CAES plants in the world are in solution-mined salt caverns (Budt et al. 2016). Despite the lack of operational CAES plants or pilot demonstrations in mines, the opportunity for CAES provided by potentially available mined cavities deep underground has not escaped the R&D community, and numerous papers and reports on technical aspects of CAES in mine openings are available in the literature. Figure 2-16 (de Prado et al. 2021) shows a diagram of a CAES system implemented in an underground coal mine.

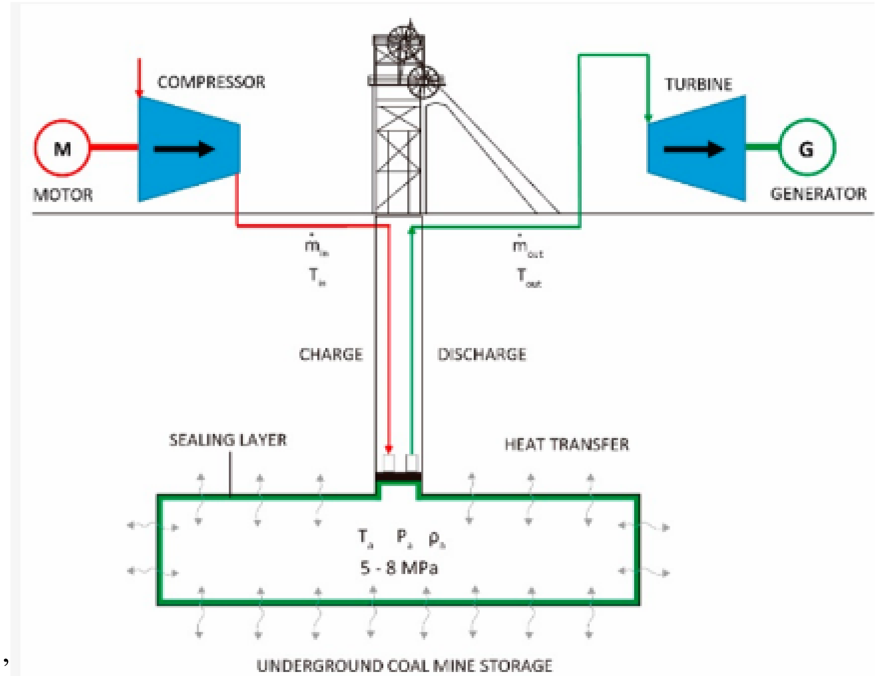


Figure 2-16. Schematic of a CAES system deployment in an abandoned mine (de Prado et al. 2021).

2.2.3.2 Technical challenges

Much of the existing literature on CAES focuses on rock caverns and lined rock caverns excavated specifically for CAES. For the purposes of this brief review, these studies are included along with studies focusing on abandoned underground mines because they share many common features and challenges in the hosting of CAES facilities. For example, whether it is a specially excavated and lined rock cavern or an unlined abandoned mine, the main requirements for a CAES project are that the mine opening (1) be accessible to receiving high-pressure air from the compression facility at high flow rates, (2) be able to hold high-pressure air (with minimal leakage) over the time period required for storage, (3) be able to deliver high-pressure air back to the energy recovery facility at a high rate, and (4) not conduct heat away from the compressed air too quickly. Other requirements include the ability to operate cyclically over decades without degradation of storage integrity, rate of air transport in and out, or energy storage efficiency.

With the described requirements in mind, early research focused on geomechanical issues (how the changes in pressure could affect the structural stability of the system) of maximum pressure allowable to avoid leakage and rock-mechanical failures arising from high pressure or from cycling of the pressure (e.g., Allen et al. 1982), a subject still under active research using modeling and simulation (e.g., Zhou et al. 2020). Goodall et al. (1988) noted that as long as the groundwater in the rock surrounding the stored gas was at higher pressure than the stored air, pressure loss should not occur despite inevitable rock fractures and non-zero permeability of the rock in which the mine is situated that could otherwise provide air leakage flow paths. The ability of the opening to contain pressurized air has been investigated and modeled by researchers at a small-scale pilot site in China (Jiang et al. 2021). Other modeling studies of containment and geomechanics have been carried out for proposed or hypothetical sites (e.g., Kim et al. 2012). One of the reasons for preferring custom-mined cavities for CAES rather than existing mines is that the caverns can be designed for CAES and avoid many of the costs of sealing and plugging openings and tunnels/shafts associated with the original mining operations (e.g., Vaatainen et al. 1995). CAES can also be combined with other energy storage technologies. For example, Geissbuhler et al. (2018) reported on the pilot-scale excavated cavern CAES experiment in Switzerland that included thermal energy storage.

Prior and current R&D work focusing more specifically on developing CAES in former mine land addresses the key issues. An excellent review of the requirements for CAES in former mine land is available in the form of a publicly accessible conference presentation (Bauer 2008). The Bauer (2008) summary came from the efforts to develop the abandoned Norton salt mine in Ohio into a CAES facility. These efforts included in situ stress measurements to ensure that the mine could hold the required pressure (Bauer et al. 2005). Analyses using computational fluid dynamics codes such as FLUENT were used by Menéndez et al. (2022) to simulate the flow and thermodynamics in detail to determine that maintaining low injected air temperature improves CAES efficiency.

Interest in energy storage in former mine land extends around the world. Early work by Hobson et al. (1978) evaluated the potential for CAES in caverns and in porous media in California. Fosnacht et al. (2015) carried out a comprehensive evaluation of the potential for hard rock mines in Minnesota to be used for CAES. Saigustia et al. (2021) reviewed several energy storage technologies, including CAES, for their potential use in coal and salt mines in Poland. Fan et al. (2018) and Deng et al. (2019) built on the fact that access tunnels and roadways in mines in China may have sufficient volume and better containment characteristics than the mined-out coal beds themselves. Advantages of access tunnels and roadways arise from their being located in potentially more competent rock with consistent engineered shape and dimensions (e.g., invert, ribs, crown) to accommodate bulkheads and so on. The authors proposed novel ideas for CAES in these parts of the mines. Cyclic loading and its impacts on geomechanical performance were the focus of modeling work reported in Schmidt et al. (2020) for a coal mine in Spain. Simulation results for 10,000 daily pressure cycles with the tunnel (both lined and unlined) pressure ranging from 4.5 to 7.5 MPa showed that the surrounding rocks can resist the loading scenarios with moderate deformation but without failure during operation times. Bartela et al. (2021, 2022) evaluated novel A-CAES (and CO_2-based energy storage systems) inspired by mines in Poland and conceived to be built using equipment installed in the mines rather than using the mine in its raw form.

In summary, significant R&D, theoretical, and modeling work has occurred and is underway to evaluate the technical feasibility of CAES in deep underground mine workings. Pilot-scale demonstrations of the technology are restricted so far to specially excavated caverns, typically with liners.

3. SITE CHARACTERIZATION AND LIMITATIONS BY TECHNOLOGY

3.1 SOLAR PHOTOVOLTAICS

3.1.1 Physical Site Characteristics

The key factor for PV generation is a combination of irradiance and the productive area of PV panels. As stated in Section 2, the amount of irradiance in the United States allows for capacity factors of 15%–30%, depending on the latitude and weather patterns. For a given location, the generation would depend on characteristics of a specific site. The physical characteristics of a potential site present the conditions for how many PV panels can be installed, at which angle they will be positioned, and what will be their operational efficiency.

Orthogonal area

Several considerations relate to land area. First, total area of land that belongs to a mine is not the same as the area that is actually used for mining. Second, the total area of land that belongs to a mine is not the same as the area that can be used for PV. The sources of mismatch in total, mining, and available land are illustrated in Figure 3-1.

Figure 3-1. Example of mine land near Murrinsville, Pennsylvania. Rectangle 1 shows Benninger Mine, McFadden Mine, and Burr Mine. Rectangle 2 shows the Slippery Rock Creek reclamation site.

Rectangle 1 of Figure 3-1 shows the actual mines recorded by Pennsylvania's Reclaimed Abandoned Mine Land Inventory[25] as Benninger Mine, McFadden Mine, and Burr Mine. This is open area that includes two inactive mines and one abandoned mine. This area could potentially be used for the development of PV systems. But not all the territory of the mines is open area. Part of the land is forest.

[25] https://www.arcgis.com/apps/View/index.html?appid=4947dd8949bf4da68374b081e797c2a0

Rectangle 2 of Figure 3-1 indicates the area recorded by Pennsylvania's Reclaimed Abandoned Mine Land Inventory as the Slippery Rock Creek reclamation site. The site has forest and a clearing that contains a refuse pile. The pile itself is not covered by trees. Furthermore, unreclaimed refuse piles and tail ponds lack topsoil, as shown in Figure 3-2. These are areas of poor vegetation, so they are visible areas or bare soil, as shown in Figure 3-3, and therefore, these areas can also be used for the installation of PV systems.

Figure 3-2. Soil on unreclaimed mine land.

Figure 3-3. Examples of refuse pile without topsoil at the Slippery Rock Creek reclamation site.

The total area that can be repurposed for PV installation is difficult to estimate. While there are estimates for land area discussed in Section 1, the mine/pile/forest area discussed previously make it difficult to estimate how much land can be used for PV.

Area can be approximated for some current and former mine land for states that provide more extensive information, such as Pennsylvania's Reclaimed Abandoned Mine Land Inventory. The highly fragmented data and missing observations prevent such data from being used in inference analysis. However, the available data still enable rough estimates of the size of an average mine. The area of individual reclamation sites was estimated to be between 30 and 500 acres, with the average being around 150–250 acres. With the conversion factor of 4–8 acres for 1 MW of installed PV capacity (Ong et al. 2013), this results in PV systems of 4–50 MW, with the average size reaching 25 MW. For instance, according to *Energy and Environmental Profile of the US Mining Industry*, larger surface coal mines in the United States can reach 3 mi long and 1 mi wide (DOE 2002). The land area of such large mines corresponds to PV systems capacity of 250 MW.

According to EIA (2019), most utility PV systems in the United States have capacity below 5 MW. These findings are partially confirmed by a Stanford University study of satellite PV images (Stanford University 2022). An analysis of images of the US territory allowed researchers to count the number of PV panels per census tract district. If a census tract district is assumed to host on average one nonresidential PV system, the census tract districts would be used to approximate the number of unique nonresidential PV systems. By assuming 370 W AC capacity, the megawatt capacity of a given installation can be further estimated; the distribution is provided in Figure 3-4.

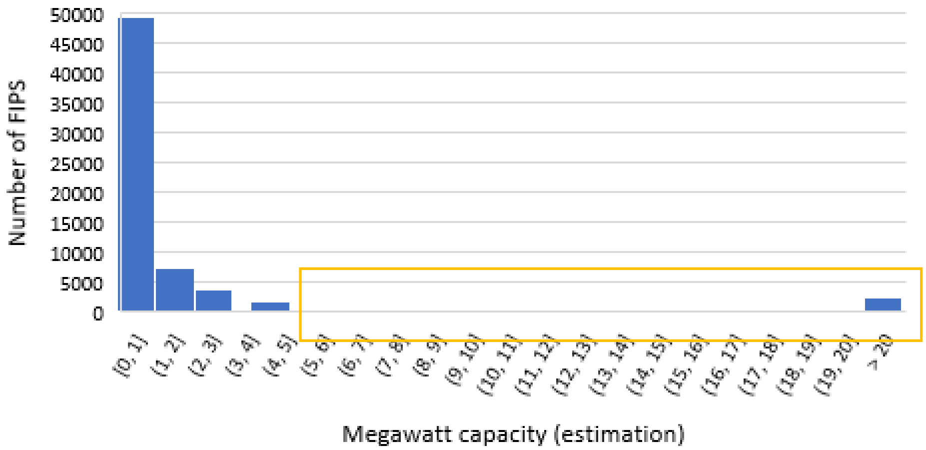


Figure 3-4. Estimate of the distribution of size of nonresidential PV systems.[26] The yellow rectangle indicates the distribution of FIPS with PV systems larger than 5 MW.

This distribution enables making an estimated conclusion, but it is not guaranteed to represent the full picture of US nonresidential PV installations. The study is limited to more populated areas of the United States, which likely ignores some desert areas that host larger utility installations. Some of these installations took place long ago and the original module size was approximately 250 W AC. Furthermore, the systems are classified as nonresidential, but that does not imply that the PV plants are owned by utilities. However, this distribution agrees with EIA data and can serve as an additional reference of PV capacity in the United States. An overview of PV systems under construction is provided by Global Energy Monitor[27], as shown in Figure 3-5. The database focuses on large systems (20 MW and above) and reveals that the upcoming systems tend to fall in the range of 70–80 MW, followed by 20–30 MW systems.

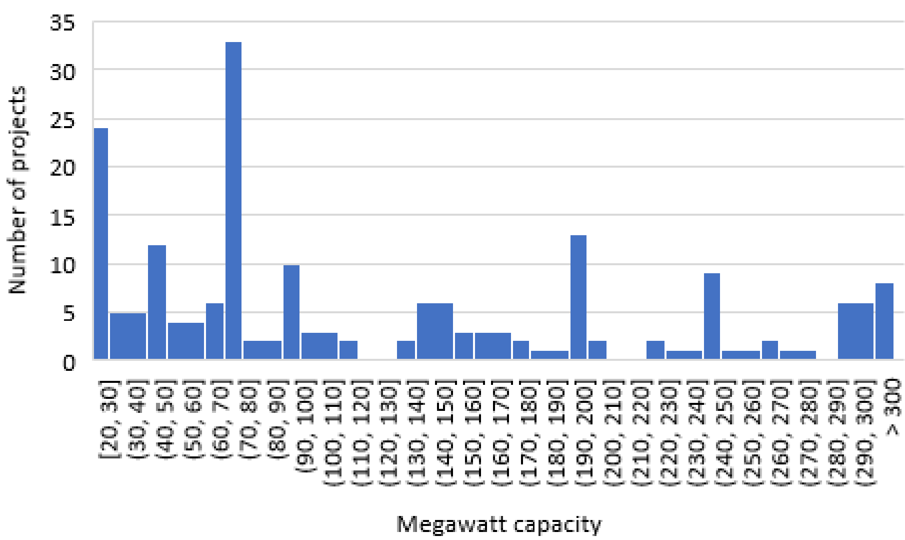


Figure 3-5. Estimate of the distribution of size of nonresidential PV systems under construction, sized 20 MW or above.

[26] FIPS (Federal Information Processing Standard) code is used to uniquely identify counties and county equivalents in the United States for research in the areas of geospatial studies, economics, and demographics.
[27] https://globalenergymonitor.org/projects/global-solar-power-tracker/tracker-map/

Depth and slope

The depth of the surface mine affects the exposure of lower levels of the mine to sun. Depth is not a concern for contour mines but may be a concern for strip or pit mines. The bench angle represents the angle of actual step in terrain and indicates the steepness of mine walls on which PV could be installed. The main indicator of the potential fitness of a mine is overall slope angle. The logic of the slope angle in a pit mine is demonstrated in Figure 3-6. The angle measures how steep the walls of the mine are from the bottom to the top.

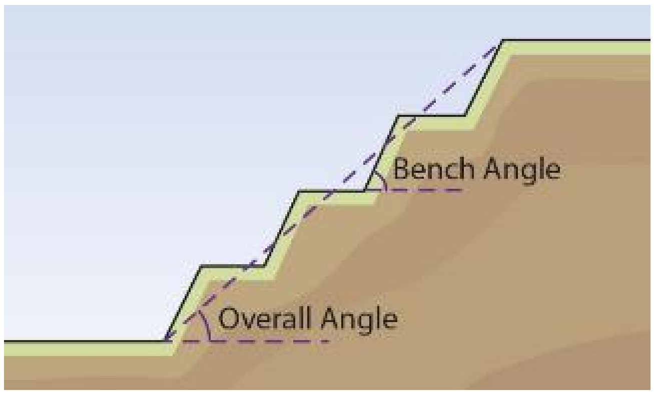


Figure 3-6. Overall slope angle of a pit mine.

The transport and protective berms in mines are optimized for excavation productivity rather than subsequent placement of PV systems, resulting in overall slope angle of up to 45°–50°, in contrast to 30° suggested in the literature (Bódis et al. 2019).

If a given coal mine is deep and has steep walls, solar elevation angle in northern latitudes may make installations infeasible. Figure 3-7 demonstrates this effect using the US National Oceanic and Atmospheric Administration's (NOAA's) Solar Calculator. The left part of the figure shows solar angle for June 30. In the event of a 30° overall slope angle (dark brown), the sun shines on the bottom of a surface mine for 9 h between 8 a.m. and 5 p.m. If the overall slope angle increases to 45° (light brown), the sun shines on the bottom of the pit for 7 h from 9 a.m. to 4 p.m. The right part of the figure shows solar angle for December 31. These numbers are consistent for various locations of the United States, with latitude ranging from 25° to 45°. For a 30° overall slope angle, the sun shines on the bottom of the pit for only some locations. Mines located at 35° or farther south get between 2 and 6 h of sunlight. Mines located to the north do not get any sunlight as the angle of 30° prevents the sun from reaching the bottom of the mine. If the overall slope angle increases to 45°, none of the regions receive sunlight.

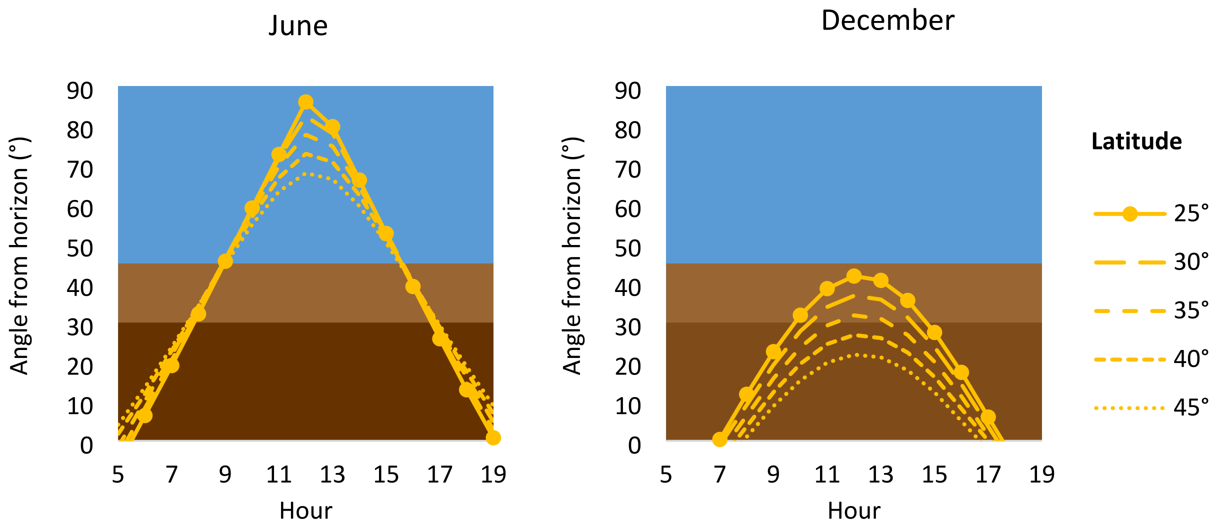


Figure 3-7. Relationship between solar angle and overall slope angle for summer and winter.

The slope considerations are relevant for contour mines and the installation of PV systems on tailing piles. In that case, the location of the PV system would still have an uneven surface, which results from earlier mining along a wall or from the piling of waste rock or mine tailings. In both cases, the slope of the hills which result from mining operation may be as steep as the walls of pit mines. The pit shading would be less of a concern for such mines, and the orientation would gain more relevance. However, the steepness of the mine or the tailing piles would affect the system design and the total cost of installation.

Shading affects parts of the mine. It changes during the day, so the accurate production of an array spread over a large area that is shaded at different parts of the day is difficult to calculate. Electrical circuits in the PV array can be arranged to minimize a combination of shaded and unshaded modules in a series string. Shading at a point may be measured with appropriate sensors, with the profile of the shading object altitude angle vs. azimuth direction entered into the system calculation software to account for the effects of shading on annual production and revenue.

Orientation

Most mines or tailing piles do not have a perfectly round shape, which—combined with the slope characteristics discussed previously—may affect the commercial viability of a mine. If a mine or a tailing pile stretches along a north–south axis, placing PV systems along walls would create a lower yield compared with a mine that stretches along the east–west axis and has a long south-facing wall. Eagle Butte Coal Mine is a relatively round mine that exemplifies this statement. The PV systems can be placed both at the bottom of the mine and along the walls. The orientation of the mine affects the potential PV production as follows. The approximate location of the mine is (44.368374, −105.530096). The sun path for the respective pair of coordinates is shown in Figure 3-8. The primary axis shows the 360° map and overlaps with the actual north–south orientation of the photo. The secondary axis shows the elevation of the sun with respect to the horizon.

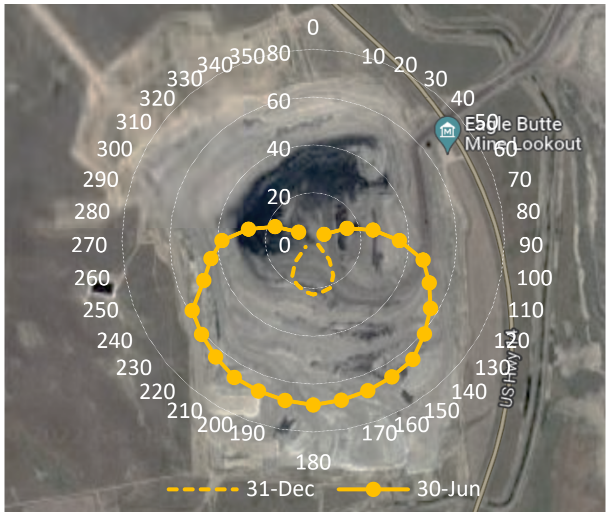


Figure 3-8. Relationship between sun path and pit orientation for Eagle Butte Coal Mine.

The sun path for summer is fully between 80° and 280°. The path that provides sufficient elevation above the horizon is further limited to 100°–260°. For winter, the sun path shortens to 160°–200°, with an elevation of approximately 20° for most hours. The use of a fixed ground-mounted PV system on the northern walls would create conditions in which modules are oriented south and exposed to the sunlight throughout the day. However, using eastern or western walls may create conditions in which the PV system is not exposed to direct sun during large parts of the day. The PV panels can also create shade for each other, which requires more sparce placement of panels and less efficient use of area. For PV to produce electricity efficiently in the mine, PV on mine walls should be facing 140°–220°, which represents only about 25% of the wall perimeter of a round mine. If a mine has an elongated shape, the stretch of the walls facing south may increase to above 25%, making increased use of PV feasible.

Geotechnical issues

There are a number of geotechnical issues which affect the feasibility and cost of installations of PV. The mines could be located in areas with rocky soil, which makes the regular piles more difficult to use and may require a different installation system. Mining operations could affect the density of the soil causing the soil to become less stable. This is found to be the case with tailing piles or tailing ponds.

Soil acidity may change as a result of mining operations, which happens particularly in coal mining. The higher acidity of the soil may result in corrosive conditions and affect the piles and racks of PV systems.

Hydrology and pit lakes

Pit mines get naturally flooded, and abandoned mines accumulate pit lakes that may require the installation of floating PV systems. Industry experts interviewed in a series of meetings during the writing of the report expressed a preference for ground-mounted systems, citing higher cost of floating systems as the main concern. Depending on the conditions of a specific site, the existence of pit lakes may prevent some older mines from being repurposed.

3.1.2 Infrastructure Access

Infrastructure important to deployment of PV includes an electrical grid and road access. Although PV does not require water to operate, water supply infrastructure may be added for fire suppression or cleaning; and integration with site stormwater runoff systems may also be required.

Transmission

Transmission lines are typically already in place for primary mining operations. Project documentation for PV sites often includes the budgets for electrical infrastructure expansion. However, depending on the infrastructure which served the mines, additional infrastructure spending may be lower than for greenfield projects.

Transmission access for mines is usually implemented through 69 or 135 kV transmission lines (Morley 1981), and some particularly large surface coal basins are served by 230 kV transmission lines (PacifiCorp 2007), from which the voltage is stepped to distribution feeders for operational levels of 4–24 kV. Single-circuit transmission lines of 69–135 kV can carry as much as 150–300 MW of active power. A 150 MW capacity PV site would require 1,200 acres of land, whereas a 300 MW capacity PV site would require 2,400 acres. As of 2019, there were fewer than 20 utility-scale PV plants with capacities over 300 MW in the United States. Many abandoned mines have more transmission capacity than the PV potential on the available land. Investors partially confirm these conclusions both directly, by indicating that existing transmission capacity for their planned projects was sufficient, and indirectly, by indicating the intended size of their projects.

Transmission and distribution substations may present a challenge depending on the operating status of a mine or ownership. Main transmission substations can be owned by a utility or by the mine owner. For loads of 1,000 horsepower (about 0.8 MW peak) or more, it is preferred that a substation is owned by the miner (Morley 1981). The average capacity on larger mines is above 1,000 horsepower, which stimulates the ownership of substations for mining operations in the United States by a miner. It is necessary to identify who owns the substations and whether the major equipment is still there.

An area of potential concern related to transmission infrastructure relates to the interconnection procedure. An interconnection study will identify modifications on the utility side of the system that will generally need to be part of the solar project budget and schedule. According to the insights obtained from the Workshops in Section 1, the current lead time to interconnect a PV power plant to PJM grid can extend to 18 months. Interconnection studies address the questions such as whether or not the grid can accommodate solar power at the time and location that the solar power occurs. Furthermore, the configuration of the system and required equipment will be different for a PV site compared with a mine, which places additional equipment requirements on substations. Modifications that may be required relate to network protectors, overcurrent protection and voltage regulation. Depending on whether a mine is fully converted to a PV generation site or whether PV is added to cover part of the load, the substation would be reconfigured accordingly.

In a Duke Energy microgrid with PV arrays (Piesciorovsky, Smith, and Ollis 2020), Schweitzer Engineering Laboratories (SEL)–651R advanced recloser relays (Schweitzer Engineering Laboratories 2023a) incorporated features such as an automatic synchronization check, which interfaces at the point of common coupling between the microgrid and the bulk electric power system. The SEL-615R advanced recloser relays (Schweitzer Engineering Laboratories 2023a) have directional overcurrent, frequency, and voltage protection schemes that were applied for the microgrid. However, in an Electric Power Board microgrid with PV arrays (Piesciorovsky, Smith, and Ollis 2020), IntelliRupters (S&C Electric Company 2022) were applied. These protection devices use a PulseClosing technology to determine whether the fault is temporary or permanent. If the fault is temporary, the devices restore power in seconds without damaging equipment with fault currents. If the fault is permanent, the devices use the intelligence in the IntelliTeam SG software to isolate the faulted segment and reroute power from other available sources in seconds. IntelliRupters are directional overcurrent protection devices that can be set with inverse time overcurrent curves for forward and reverse directions. Furthermore, they can be coordinated with each other and with feeder fuses for currents flowing in a reverse or forward direction, depending on the microgrid operation mode (grid connected or islanded). In other PV array systems (Piesciorovsky, Smith, and Ollis 2020), the protection schemes have SEL protective, control, and communication devices. The control systems of the solar array and battery bank inverters include an undervoltage protection algorithm that detects DC and AC circuit faults and automatically shuts down the inverter in approximately 5 ms. The undervoltage protection algorithm for the inverter control systems provides the primary protection for faults in the DC and AC circuits. The relay that performs the protection scheme for the microgrid trips the breaker located at the transformer low-voltage side. The undervoltage (27) and voltage balance (60) elements were used to trip to all unbalanced electrical faults. The elements 27 and 60 were enabled as a backup protection scheme, and the volts-per-hertz (24) element was used for failures at the inverter control system.

The total system inertia comprises the combined inertia of most of the spinning generation sources and the connected loads (Gonzalez-Longatt 2012). The low levels of rotational inertia are given by the inverter-based distributed generators (IBDGs) based on PV arrays; they do not provide any rotational inertia, and they have some effect on the power system's frequency dynamics (Rycroft 2017). The loss of rotational inertia, and its increasing time variance, leads to frequency instability phenomena (ABB Ltd 2012) in the electrical grid. Furthermore, PV arrays present low power quality characteristics because they have individual current sources with independent DC current ripple of the converter ripple. Then, the PV array and converter ripple currents are not synchronized, and they produce subharmonics in the DC circuit that increase the total harmonic distortion in the current waveform (Halpin 2006). The lack of inertia limits the frequency variations in the case of sudden load or generation changes. The penetration of PV arrays based on renewable energy can reduce the inertia of the grid, and the synthetic inertia can be introduced using smart grid techniques to overcome the smaller interia (Rycroft 2017). Therefore, energy storage systems based on providing primary and long-term support energy can also provide the synthetic inertia or dynamic support on these cases. Although many PV arrays with storage systems installed do not have a means of communication between all devices in the network (Rycroft 2017), the interconnection and communication between the microgrid protection and control devices is a feature that need to be designed for each particular project to reach an effective use of the distributed energy storage systems and provide the needed frequency (Schmutz 2013).

These requirements are specific to the site and the local system operator, which does not allow for making any general assumptions about which aspects of the transmission and distribution system present a barrier to development of PV on current and former mine land.

Roads

Since PV systems do not require shipping heavy or bulky items, regular road access is sufficient for building and operating a PV plant. US mines are typically served by paved or gravel roads, which makes road infrastructure an accessible option for PV. Furthermore, most PV equipment comes in standard shipping containers. However, other equipment such as transformers may be bulkier and present stricter requirements to accessing the site. The location of the substation would also have to account for road access. Some mines and tailings piles may be steep or have a small turning radius.

3.1.3 Regulatory Considerations

Investors mention regulation and permits as the third largest and important part of project feasibility. According to a series of stakeholder meetings throughout the workshops as mentioned in Section 1, regulatory challenges pertain to several major areas.

- The filing procedure is subject to local legislation and requires thorough knowledge of the rules in each specific state. Bond releases likely affect the construction on larger sites. Multi-agency federal reviews affect project feasibility.

- A change in land use may be required as land transitions from coal mining to the generation of electricity.

- The interconnection procedures and rules related to utility service territories are an important part of the development process. Interconnection queues is likely one of the longest parts of the approval procedures.

- The local environmental regulation, including wildlife and fish protection, may require working with some of the federal and local regulators, such as offices overseeing nature preservation.

- The division of land surface and underground property rights does not likely affect solar generation significantly, although it may affect other technologies that use shaft mines.

3.1.4 Decommissioning Considerations

Decommissioning of mines

The decommissioning of mines and the preparation of the initial field for development of solar projects involves several considerations (DOE workshops).

- The reclamation still has to take place, although to a smaller extent compared with the full reclamation and restoration.

- The preparation of a former mining site for PV development requires grading and ensuring that there are no areas that would be subject to subsidence. Soil stability is an important consideration since the soil material is not uniform across mines.

- Water management is an important factor in some areas because of possible issues with water contamination and flooding.

Decommissioning of power plants

At the end of a project performance period, the alternative courses of action are as follows:

- Continue to operate the plant even with performance degradation and high operations and maintenance (O&M) costs

- Refurbish the plant by replacing any failed equipment

- Reconfigure a smaller but properly operating system

- Repower the plant with new inverter and PV modules but leverage existing infrastructure and interconnection arrangements and power purchase contracts

- Remove the system and restore the site to an acceptable condition

Operational health and safety hazards

The requirements related to operational health and safety include hydrological reclamation planning and flood control (Virginia Law 2022). The main occupational health and safety issues related to installation and long-term operation of a PV plant include electrical safety and arc flash hazard (NFPA 2019). PV modules and series strings of modules can be energized whenever the sun is shining, requiring training and personal protective equipment for workers. System topologies that provide shutdown at the module level (microinverters) or locally to the array reduce this arc-flash hazard. Safety training is required for PV facilities staff.

Environmental hazards

Some of the main environmental hazards related to decommissioning of mines have been discussed in previous sections. Besides the mentioned hazards, water management presents a major environmental concern in some mining regions. Wildlife and habitat are considered a particularly important environmental factor. Some environmental hazards are related to the operation and decommissioning of PV systems. The aluminum racks can be recycled at a considerable salvage value. Steel piles and purlins may also be recycled, although they are not a significant source of salvage value. Other components such as PV modules and power conditioning electronics may be expensive to dispose of properly. Some components, such as PV modules, may contain Pb or, if they are the Cd telluride type, other metals. Other materials involved in a PV module might include antimony in the glass, plastics and adhesives used. These hazardous materials may be avoided in the first place through procurement specifications or would need to be disposed of in an environmentally responsible way.

Other resources

The use of former mine land is not limited to PV. Some former mine land sites can be used for commercially extracting other minerals. As an example of mineral extraction, refuse piles from one of the southern counties of Virginia were found to contain the minerals listed in Figure 3-9.

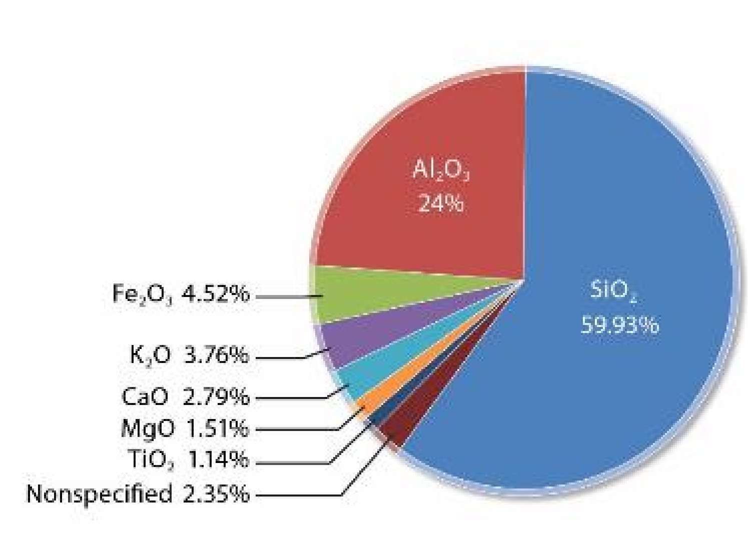


Figure 3-9. The mineral structure of a tailings pile.

Residues may contain commercially recoverable volumes of rare earth elements (REEs). Usually, the commercial mining estimate for REEs is on the order of hundreds of parts per million. Currently, much commercial mining takes place in China and Australia. The commercially recoverable volumes can be larger or smaller depending on the amount of effort put into mining and separation. It may be more cost-effective to produce REEs from coal waste piles.

The volumes of REEs from abandoned tailings piles identified in Figure 3-9 are provided in Figure 3-10 (blue). The green lines in Figure 3-10 indicate the minimum to maximum concentrations of REEs reported by prospects or commercial mining sites in Australia (Geoscience Australia 2018). Commercial mining concentrations represent a benchmark for concentrations that would justify greenfield development of lands. The results indicate that for some REEs, such as Ce, La, and Nd, the concentration in refuse piles is much lower than in cites that are considered or used for commercial mining. In other REEs, such as yttrium and Li, the concentration is closer to commercial mining sites.

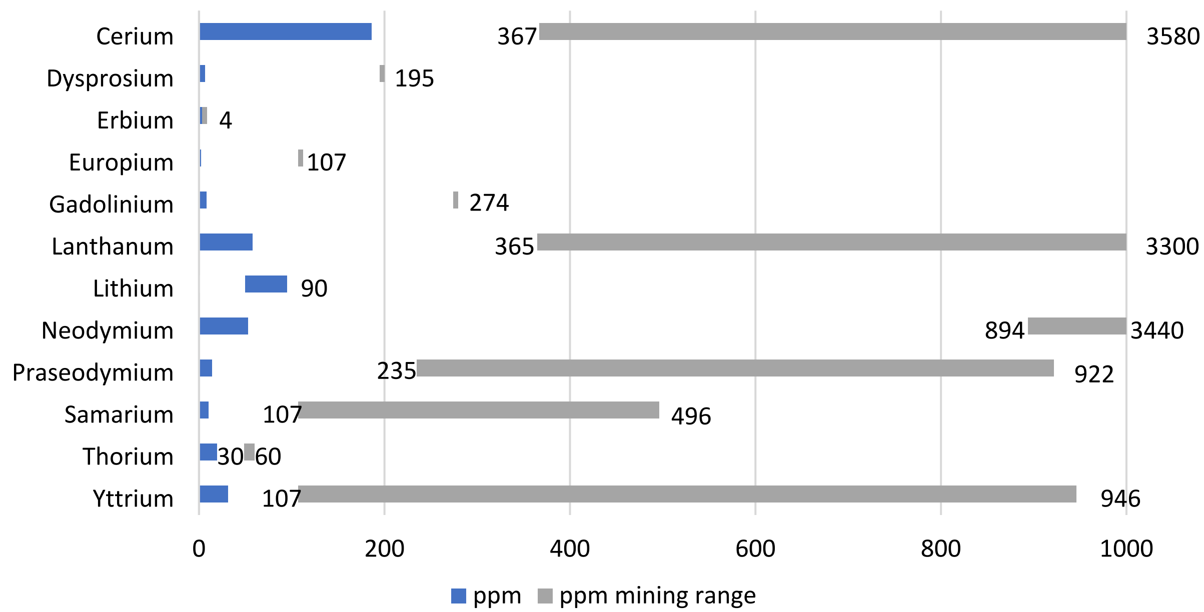


Figure 3-10. REE concentrations in a refuse pile, and the range of concentrations at commercial mining sites in Australia.

Some former mine land sites can be repurposed for nonindustrial uses, including municipal, environmental, and cultural locations. The former mine land can also be used for landfills. Some communities tend to prefer repurposing mine land for wildlife conservation. According to existing research (Mulvaney 2017), installation of PV systems on public land has caused controversies because many local communities prefer the land to be used for habitat, cultural heritage, and other noncommercial purposes.

3.1.5 Economic and Resource Considerations

The development of PV on mine land requires some further analysis of resource availability besides the physical characteristics of the location and access to infrastructure. The two main resources to consider are labor and capital. Another factor to consider is market for electricity.

Labor availability

Labor is one of the primary inputs into PV operation. Mining and PV have very different labor requirements and competences, which has created consensus among investors that training would have to be provided through vocational schools and labor could need to be sourced beyond the immediate municipality or county. Most investors agree that the broad market is capable of supplying qualified technical and support labor if the jobs are created. Local workforce development efforts can involve local trade schools, community colleges, and universities.

Financial resources

Current industrial evidence from the expert interviews, reviewed in Section 1, suggests that mine renewable investments are financed through a combination of equity and debt. The first source is 100% owner equity, and it is usually selected by vertically integrated utilities. Utilities plan and implement PV power plants fully through their own funds and include a standard rate of return in the justification of the tariff as they pay back the investment.

There may be multiple sources of equity. In such projects, about 20% of the total equity is provided by the major investor. The other 80% of total equity is raised for the project through the capital markets. A special type of equity investor, a tax equity investor, is especially positioned to monetize the federal investment tax credit and depreciation. The other type of financing is debt in the form of a loan from a bank. Debt is paid back at a fixed interest rate, unlike the equity investment, which is paid back at a rate of return dependent on project financial performance. An example of a bank lender is Wells Fargo.

Although not preferred by existing developers, other options include financing parts of the project through partner public debt or through federal infrastructure funding.

Markets for electricity and ancillary services

Access to electric power markets presents another requirement for operating a PV plant on former mine land. PV are not capable of providing system services such as regulation or spinning reserves and their revenue is limited to selling active power. PV projects could sell active power in three main ways. The first way is to participate in wholesale markets, such as PJM or MISO, and receive the locational marginal price for the volume supplied to the grid. The second way is to get revenue through utility rates. A regulated utility is allowed to submit the cost base and the rate requirement for a review of the local Public Utilities Commission and receive an approved fixed amount for each MWh of generated power. The third option is to establish long-term contracts or PPAs. In this case, a PV facility would supply electricity to the grid but get compensated directly by a customer that is located within the acceptable power flow range and is willing to withdraw the respective volume from the grid. PPAs would be affected by the existing legal and business practices. For instance, rural electric cooperatives may be unable to enter a PPA with independent power producers, in which case the agreement would be implemented through a local utility.

An additional stream of revenue is presented through carbon markets. The market for renewable energy credits (RECs) is a source of revenue for solar projects associated with the environmental attributes. In some locations where laws require that the energy be generated locally, the REC value, often listed in US dollars per megawatt hour produced, is sufficient to enable project cost-effectiveness. For example, at the time of writing, REC values recorded by Flett Exchange[28] were $0.04/kWh in Pennsylvania and $0.05/kWh in Ohio, which is on par with the prices for active power through PPAs. In areas without those special restrictions, the REC value can be quite low and not a significant source of revenue.

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[28] https://www.flettexchange.com/

3.1.6 Social Considerations

Social advantages or barriers are another factor that can facilitate or prohibit installation of PV. Although no research was found on PV opposition specifically in the context of mines, broader research suggests that there still may be social advantages or barriers to deploying PV on mine land.

The first group of factors relate to the installation of PV irrespective of mine land. The large categories of factors specified in existing studies relate to environmental values (Mundaca and Samahita 2020), trust for the developers (Carlisle et al. 2015, Adesanya et al. 2020, Crawford et al. 2022), and visibility (Fernandez-Jimenez et al. 2015, Keeley et al. 2021, Carlisle et al. 2016). Visibility is a less pressing factor in the adoption of PV on mine land. Mines are located outside of urban areas and are not likely to be seen by the local population on a daily basis. Trust is a significant factor that affects new power plant projects regardless of their development on mine land.

Environmental values

Environmental values, including pollution abatement and climate change mitigation, are some of the most significant factors in adoption of PV, and these concerns are specific to adoption of PV on current and former mine land. This factor is relevant across cultures, races, and economic conditions (Feron 2016). The willingness of end users and local communities to accept the installation of PV raises a question of whether environmental values are equally strong in mining regions and other regions. This question was raised consistently in research on US regional adoption of renewables, and some evidence indicates that communities in regions with extractive economies are more likely to oppose the use of renewables (Olson-Hazboun 2018, Olson-Hazboun et al. 2018). There is also alternative research evidence that societies in fossil fuel economies still use PV, and the concern for the environment remains the main driver of social acceptance (Alrashoud and Tokimatsu 2020). Figure 3-11 illustrates the correlation between the cumulative number of PV tiles and the cumulative number of mines in the United States. The plot was created using two main sources of data: the Stanford study discussed in Section 3.1.1 and the US Mine Safety and Health Administration (MSHA) Mines Data. The data entries were aggregated by FIP county level. The vastly different scale of numbers (1–3 mines per county vs. hundreds of PV tiles) justifies the use of the logarithmic scale. The results indicate that there is no negative correlation between the number of mines per county and the number of PV tiles, but further research with more covariates is needed to make any definite conclusions of PV acceptance.

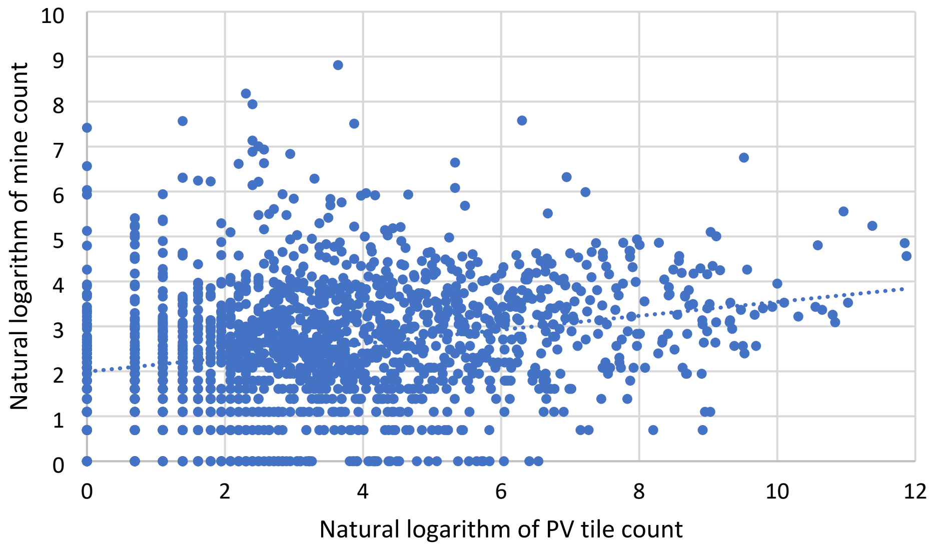


Figure 3-11. Logarithmic scatter plot of the number of PV tiles and the number of mines per county.

3.2 PUMPED STORAGE HYDROPOWER

3.2.1 Physical Site Characteristics

The primary physical site characteristics influencing PSH development are the reservoir storage volume and the hydraulic head between the two reservoirs. The water conveyance structures can be appropriately sized to allow for certain flow rates. Based on head and flow, the power rating for the system can be determined, as calculated in Section 2. Power can be generated for several hours throughout the day, typically ranging from 4 to 10 h for most PSH projects. In addition, the topography and presence of existing boreholes will dictate the arrangement, length, and sizing of water conveyance structures. Larger sized projects are more economically feasible. From the industry stakeholder interviews, it was found that most US developers target at least 100 MW. Most projects tend to be over 100 MW, while some operational projects are smaller than that.

The geologic stability of the mine land used for PSH reservoir construction is extremely important to ensure reservoir water containment under the highly variable loading conditions. Reservoirs are quite large, and the water stored within create immense weight and pressure on the reservoir bottom and sides. To maintain water volume within the reservoir, adequate reservoir lining is required.

Water quality within the reservoirs is important when considering the risk of environmental releases. Upper reservoirs may require a spillway to avoid overtopping failure from high-precipitation inflows. This is also important to avoid negative impacts to wildlife in the area that may use the water body, either intentionally or unintentionally.

3.2.2 Infrastructure Access

PSH projects require access to transmission infrastructure, which may be present at a mine site or may require upgrades to match the power load at the site. Road access is also needed to transport construction material and allow for laydown area for construction.

In the hydropower plants, a pumped storage machine can operate either as a motor or a generator. In addition, the grid-connected and islanded cases with hydropower plants have high spinning inertia cases, and they are not like PV arrays or wind farms that could have a small or medium inertia at electrical fault situations, respectively (Piesciorovsky, Smith, and Ollis 2020). Traditional protection philosophy has required external current transformer/ potential transformer (CT/PT) switching or the use of separate relays, one to protect during motoring operation and one to protect during generator operation (Schweitzer Engineering Laboratories 2023b). Some hydropower plants have protective relays that have internally connections that allow to correct the phasing introduced by the reversing switch. The logic ensures that the phasing of the differential element is correct and that the phase rotation is correct. This allows a pumped storage hydro unit to be protected with a single protective relay without the need to externally switch the CT or PT secondary wiring.

In hydropower plants, the frequency range tracking is between 5 and 120 Hz (Schweitzer Engineering Laboratories 2023b) because generators may operate at frequencies significantly different than the nominal frequency. For example, hydropower generators may overspeed by as much as 50% when rejected from the system. The total start time can be as long as 30 min for the hydropower generators (Schweitzer Engineering Laboratories 2023b). During this time, the frequency may be less than 20 Hz for an extended period. Therefore, some hydropower generator protective relays have a wide-range frequency tracking algorithm. To ensure that all protection functions are secure and dependable regardless of the system frequency. In the motoring mode, the power of the generator draws from the power system, and it is dependent on the prime mover; hydro turbines with their turbine blades above the tail race water level will draw between 0.2% and 3% of their rated power. Therefore, to detect that the hydropower generator is in the motoring mode, a very sensitive directional power protection function (32) is needed. Like all types of generators, the hydropower generators need synchronization-check elements. The synchronism-check function (25) is extremely accurate, and it provides the supervision for the acceptable voltage window and maximum percentage difference, maximum and minimum allowable slip frequency, target closing angle, and breaker closing delay, to perform the interconnection with the electrical grid (IEEE 2009).

3.2.3 Regulatory and Legal Considerations

The regulation of pumped hydropower on open pit mine land is partially done through local laws and partially through the federal requirements. There exists a FERC guidance (FERC 2019) that explains permitting of pumped hydropower projects on mine land which includes the description of regular and expedited licensing processes for closed-loop reservoirs. The main considerations highlighted in the guidelines include

- Geology and soil,
- Water resources,
- Fish and aquatic resources,
- Terrestrial habitat,
- Endangered and protected species,
- Tribal resources,
- Socioeconomics, and
- Aesthetics and recreation.

The license process requires documented evidence of consultations on the areas of concern with relevant stakeholders such as state and federal agencies, Indian tribes, local landowners, nonprofits. The objective of the stakeholder meetings is to identify issues and needs, conduct studies to identify project-related impacts, develop mitigation and enhancement measures.

3.2.4 Decommissioning Considerations

Decommissioning of PSH projects vary state to state. They may require considerable work to ensure proper environmental mitigation of the water body and associated land. Equipment and other construction material may need to be retrieved. Underground water conveyances may need proper sealing to avoid human hazards. The requirements related to operational health and safety include hydrological reclamation plan and flood control (Virginia Law 2022).

3.2.5 Economic Considerations

The next potential barrier to development of open pit pumped hydropower is access to financial resources. There are two different ways in which US developers finance pumped hydropower projects. Vertically integrated utilities finance construction through own equity and debt. Utilities operating in power markets tend to split the investment. Part of the cost, which was found in some instances to be around 20%, is financed through own investor equity. The other part is raised in the markets. Other sources, such as public bonds though public private partnerships or public development grants, were not found to be significant for open pit pumped hydropower. Some developers mentioned tax credit as a helpful but not critical component of the financial structure.

The final but important consideration is access to markets for electricity and ancillary services. The first form is revenue agreements that are usually implemented by regulated utilities in vertically integrated systems. In this case, a utility would file the revenue requirement details to a local regulator, and in the event of a positive decision include the development cost in its rate.

The second form of market access is through competitive markets for electricity and ancillary services, which is usually implemented by independent power producers. There is evidence from developers in the United States that arbitrage revenue from electricity markets is not sufficient to cover the investment costs of building an open pit pumped hydropower project on former mine land. However, as revenues from ancillary services are factored in, a project becomes feasible. Ancillary services are defined broadly and depend on a market, but could include frequency and voltage support, and a variety of reliability payments, compensated through capacity or reserve markets. There is no documented evidence on the revenue structure of pumped hydropower projects. However, a series of investor interviews that took place during the preparation of this report allowed to establish some ballpark estimates. According to investor opinions, revenue from ancillary services could make up to 70% of total project operating income. Another 30% would come from arbitrage in electricity markets.

3.2.6 Social Considerations

The typical areas assessed related to social considerations include demographics, perception of own region, openness to large infrastructure development, openness to renewable energy and storage in the particular community, anticipation of benefits and challenges related to the project, sources of news about the project.

There are no dedicated studies of hydropower project acceptance in the United States. A study from Germany shows that the general acceptance of PSH projects in mines is related to a number of factors. One factor is the public perception of mines and self-perception, for instance as a coal mining community. As mentioned in Section 2, a mine should be operational at a point when it starts being repurposed for an underground pumped hydropower plant. Therefore, the local communities may oppose the conversion of an active mine to something which is unrelated to mining activities. A study from German Ruhr area (Grunow et al. 2013) found that a transition from coal is only viewed positively by about 50% population. The redevelopment of coal mines for commercial or industrial purposes was viewed positively by about

60% of the population. Notably, these results were a consequence of traditional rather that anti-environmental mindset. These results were obtained in the area where above 70% of population support PV and wind and over 40% of population negatively perceives coal mining, fracking, and nuclear energy. Environmental values themselves do not have the same positive effect on acceptance of pumped hydropower as they have on acceptance of renewable energy sources such as PV or wind. Similar considerations may pertain to hard rock mining, although hard rock mining is less sensitive to energy transition than coal mining.

There exists evidence that being familiar with the technology facilitates public acceptance of pumped hydropower projects. The same study from Germany found that 80% of residents who were informed about pumped storage technology supported the project, compared to the average acceptance of 50%. The public was also found to express an interest and judgement with regard to the actual configuration of the project. When offered to rate two types of technical plans for the project, 75% of the local residents showed preference for one of the types.

3.3 COMPRESSED AIR ENERGY STORAGE

3.3.1 Physical Site Characteristics

3.3.1.1 Height, depth, land area, storage, and topography

CAES needs adequate overburden stress to hold relatively high-pressure air. The current CAES plants in solution-mined salt caverns operate at a maximum pressure of approximate 70 bars (7 MPa or 1,000 psi), corresponding to the hydrostatic pressure at a depth of 700 m beneath the groundwater table. Lower pressures and shallower mine depths can also be used. Aside from pressure limits imposed by geomechanics and rock stress, air pressure is limited to values below which excessive losses occur by air displacing water in fractures and permeable zones in the rock surrounding the mine opening. Hydrostatic pressure and capillary entry pressure both serve to maintain groundwater in what could otherwise be air leakage pathways. If air leakage is not preventable by natural features of the mine, the workings can be lined with cement/concrete/grout or other low-permeability materials.

CAES requires a volume of open space in the mine free of water flooding and backfill. A typical large underground coal mine in the United States has extracted approximately 6 million short tons of coal, which corresponds to approximately 4×10^6 m^3 of coal (assuming a density of 1,500 kg/m^3). For mines in which the openings have not collapsed, this volume would theoretically be available in the abandoned mine, but it is a conservative estimate of volume available for CAES because it does not include all of the tunnels, shafts, and other workings that may have been excavated to access the coal and operate the mine. The same argument holds for limestone mines and precious metal mines for estimating mine volume—volume estimates based on extracted limestone/ore are conservative (smaller) than actual volume available because of the large fraction of support tunneling that exists in any underground mine. Notably, bigger is not necessarily better when it comes to the volume of the openings for CAES. Rather, the volume available for CAES needs to be sized to match the compression and energy recovery requirements of the CAES plant. This volume-matching requirement can potentially be met by the use of bulkheads and backfill to customize the CAES volume in the mine as needed.

For surface requirements, CAES needs shafts or adits for holding air ducts to convey high-pressure air in and out of the storage volume and space for surface facilities on-site for compressors and energy-recovery turbines. If advanced approaches such as A-CAES or isothermal CAES are used, space may be needed for surface facilities for aboveground thermal energy storage systems, although development and use of subsurface thermal energy storage opportunities is compelling and may be more attractive.

One major factor for storing compressed air in a mine is whether the mine can contain high-pressure air. Assuming the shafts, adits, and access tunnels are sealed off from their openings to the ground surface (e.g., by installing well-designed bulkheads), compressed air is very likely to be retained within deep subsurface mines. Natural fractures and intrinsic rock permeability are not a cause for concern for storage integrity because of the hydraulic barrier provided by groundwater. In short, deep mines are far below the water table and there is a strong drive for water to enter most deep mines, as evidenced by the need for pumping to keep them dry and accessible. This water pressure exists throughout the fractures and pore space above, below, and around every tunnel and working in the mine. The groundwater in the rock effectively blocks air from escaping. Therefore, as long as the air pressure is kept lower than the hydrostatic pressure of the local groundwater at any given depth, underground openings can contain compressed air. The air pressure can be higher than the local hydrostatic pressure in many cases because of the capillary entry pressure, which means air must exceed a certain pressure higher than the hydrostatic pressure to displace water held in small pores by capillary forces. Furthermore, with respect to storage integrity, air pressure in a CAES facility cycles between high (during storage cycle) and low (during recovery cycle) pressure. Therefore, the mine does not need to store the high-pressure air indefinitely, and in some cases, the mine may only need to store compressed air for 10 h or so. Although every mine is unique and pressure testing will be a primary activity in mine characterization for CAES development, in theory, deep mines (greater than 500 m deep) should be able to store compressed air as long as shafts, adits, and other access tunnels are sealed off from their connection to atmospheric pressure (the ground surface).

For shallow mines and caverns, or for situations in which the water table is very deep, the tunnels or cavern volume may need to be lined with concrete or cement to seal fractures that could leak compressed air. Lining of tunnels is common where water seeps in or where there are fracture zones that leading to spalling and so on. Lined caverns are studied in the CAES context (e.g., Kim et al. 2012). Lining of the workings ensures storage integrity for shallow mines where groundwater pressure may not be sufficient to contain compressed air, or where natural geomechanical stresses are small and additional tunnel strength is needed to meet pressure requirements of the system.

In summary, information to be collected includes the following:

- General information related to the mine, such as the type, location, topography, depth, and status (e.g., abandoned, time of abandonment)

- Information related to underground workings, such as the volume of mine openings, water incursion level (flooding), tonnage removed, geology, structure, stress state, temperature information, hydraulic potentials, history of mine pumping, and ventilation

3.3.1.2 Geology

CAES generally requires competent rock with low intrinsic permeability and geomechanical properties capable allowing the facility to accommodate high pressure and pressure cycling. Lithology consisting of bedded or diapiric salt are excellent, as is crystalline rock. Sedimentary carbonates and clastic rocks are likely less well suited to CAES without installation of liners, although groundwater saturation and capillary entry pressure may prevent air loss.

3.3.1.3 Environmental sensitivities

No specific environmental sensitivities are anticipated for CAES in mines except for those related to the surface infrastructure consisting of transmission power lines and turbomachinery. In the case of coal mines, the emission of CH_4 and potentially other gases above background levels during CAES cycling needs to be evaluated.

3.3.1.4 Other site characteristics

CAES involves injection of air that contains O_2, which creates the possibility of enhanced oxidation and/or fires in coal mines when air contacts coal. This motivates development of CAES volumes in tunnels and shafts away from the main coal seams. Other working gases such as CO_2 may also be used in a closed-loop compressed gas energy storage system. Knowledge gaps for mine CAES include reactivity of O_2 in air with coal and CH_4 in the mine, other minerals, tolerable delta-T (temperature difference between the injected air and mine void temperature), thermal losses to wall rock, and effects of evaporation and condensation of water into/from air during cycling and its impacts to surface electricity generation equipment.

A good understanding on the subsidence from previous mining activity and potential mine water inflow will help evaluation of potential storage volume and the geomechanical state of the system (e.g., potential fractures for leakage).

3.3.2 Infrastructure Access

Because CAES interconverts electricity and mechanical energy, CAES facilities need a connection to the electricity grid. In addition, diabatic CAES is used in most applications, and it recovers energy using a gas turbine. This approach also requires a NG pipeline to the electricity-generating turbine. New ways of recovering energy are needed to avoid burning fossil fuels, such as A-CAES. These new methods generally involve storing the heat of compression and recovering it during expansion in the turbine, making the process adiabatic. For this method, thermal energy storage systems or structures are needed, which may require additional surface land availability. However, subsurface thermal energy storage in the mine itself offers enormous potential to eliminate the need for NG and advance the technology of A-CAES.

3.3.3 Regulatory and Legal Considerations

According to Fosnacht et al. (2015), FERC orders regarding CAES include the following:

- FERC Order 755 for storage technology requires regional transmission organizations and independent system operators to adopt a two-part market-based compensation method for frequency regulation services—a capacity payment reflecting opportunity costs and a market-based performance payment—rewarding faster-ramping resources, such as batteries and flywheels.

- FERC Order 784 requires high-voltage interstate transmission operators to recognize the value of energy storage systems that can quickly and precisely dampen potentially dangerous disturbances in electrical frequencies.

- FERC Order 792 added energy storage to the category of resources eligible to interconnect with the electric grid. Thus, energy storage can receive rates, terms, and conditions for interconnection with public utilities that are just and reasonable and not unduly discriminatory.

- FERC Order 890 requires ISOs to develop tariffs, market rules, and control algorithms to open markets for non-generation energy storage technologies to provide ancillary services.

Regulations for energy storage at the state level vary.

3.3.4 Economic Considerations

The economics of underground CAES depends very much on how the technology will be deployed. In conventional diabatic CAES as currently implemented in the two existing underground CAES plants, NG is used in the expansion process. It is estimated that an equivalent of 1 kWh of energy from the NG is needed to generate 3 kWh of energy from the CAES plant (Menéndez et al. 2019). Therefore, the economics of conventional CAES depend on the price of NG, which makes its cost less than PSH only if the fuel price is low. However, this may change for CAES given the recent research that is being carried out to advance the way energy is recovered. For example, A-CAES systems store the heat generated during the compression process and recover it to preheat the compressed air during electricity generation in the turbine. Other R&D is being done to make use of the cooling during the expansion process to precool the compressor. Opportunities for hybrid configurations of energy storage involving CAES exist that would exploit the advantages of mine CAES (e.g., abundant and free working fluid and mined volume) while mitigating the disadvantages (e.g., use of NG in the recovery process).

3.4 GEOTHERMAL

3.4.1 Physical Site Characteristics

Several potential applications of geothermal energy on mine land (**Error! Reference source not found.**) could reduce the use of traditional fossil fuels for electricity and heat generation. The temperature of a geothermal resource and end use are the main parameters that determine the application. When geothermal energy is used for electricity production, evidence of permeable aquifers is another critical parameter. The potential geothermal system's design and benefits will depend on the site location and proximity to the area of need. Electricity can be generated using a binary cycle plant if the geothermal reservoir temperature exceeds 95°C. In the case of dry/flash steam generation, this temperature needs to be much higher. Mines associated with epithermal mineral deposits with high geothermal gradients are possible candidates for these applications. At mines with high geothermal potential, geothermal energy can also be used for some of a mining operation's electrical power needs. Direct use applications are on the other end of the spectrum, where temperatures as low as 12°C–20°C can be used for heating drifts, processing ore, and district heating and cooling. Coal mines are good candidates for direct use applications. The most common geothermal applications for mines will be for direct heating and cooling.

High-temperature geothermal electricity projects are typically associated with large reserves of hydrothermal resources because an underground reservoir containing fluids is needed to generate steam that activates a turbine to generate electricity (van der Meer et al. 2014). A number of geothermal exploration approaches, such as geothermal play fairway analysis, can be used to help assess the feasibility of a specific area for high-temperature geothermal resources (e.g., Siler et al. 2017, Faulds et al. 2017, Shervais et al. 2020); resource assessment methods related to geothermal technology on mine land are described in greater detail in Section 4. Power plant viability depends on the suitability of an area for geothermal energy production, which is a complex combination of many environmental factors (e.g., Coro and Trumpy 2020). Only limited areas have both sufficiently high geothermal gradients and suitable reservoirs to allow for geothermal electricity production, although the development of enhanced geothermal systems (EGSs) would expand the potential development of high-temperature resources throughout the United States (e.g., Augustine 2016). Low-enthalpy geothermal projects with a focus on direct heating applications, such as district heating, greenhouse complexes, or industrial use, are more frequent.

Most active mines have on-site space heating or cooling needs, such as within administrative buildings or live-in camps. A switch from traditional heating and cooling to GSHP systems could result in electricity savings and reduced CO_2 emissions.

Many hard rock mines (i.e., where ore—a rock or mineral that contains valuable constituent—is recovered) are in remote locations, away from existing transmission lines. Such mines need to develop on-site power generation capabilities or build transmission lines. If available, in situ geothermal power generation can provide an alternative energy source for all operational needs and result in significant cost savings (e.g., Reyes et al. 2011).

For former mine land, knowledge of the following parameters is important to evaluate their potential: the location and closeness to a community, minerals mined, volume excavated, host rock, maximum depth, depth to underground workings, operating period, date abandoned, volume and geometry of underground workings, current use of land, and known surface communication features such as shafts, temperature, water chemistry, hydraulic potential, geothermal potential, and mine blueprints or other information.

The deposit's geological structure defines the rocks' thermal conductivity coefficient. In addition to temperature, geothermal gradient, and heat flux, the geothermal energy of mine water is also dependent on the position of the mine in the regional groundwater cycle and the area's geothermal activity.

Nonactive or abandoned mines are often filled by groundwater and runoff. This water volume can be used in direct heating through GHP systems. This geothermal resource leverages existing underground gallery networks or open pits. The energy extracted or transferred using heat pumps can be used for heating and cooling commercial, industrial, residential buildings, greenhouse complexes, and data centers.

Important factors in determining a GHP system's feasibility include the water's temperature and the reservoir's size. The optimal reservoir temperature can sometimes provide direct heating or cooling. However, in most cases, with moderate temperatures, a heat pump is used to either extract heat from water or deliver heat to water. If heat pumps are combined with gas-powered boilers, higher-temperature water for domestic hot water needs can be provided.

Water chemistry assessment is important during geothermal operations to configure the GSHP system optimally, and to anticipate the risks of scaling and corrosion. The suitability of existing fluids or required treatments depends on if the system is an open-loop or closed-loop system. In the open-loop system, extracted groundwater passes through a heat transfer system and is reinjected into the source reservoir or disposed of as surface water. The closed-loop system has a piping system with a fluid circulation in contact with the reservoir, and the heat transfer system interacts with the circulating fluid. Open-loop systems are more common and simpler than closed-loop systems. The closed-loop configuration is used for mines with contamination issues or insufficient water volume. The two systems are illustrated in Section 2 (Figure 2-12).

The usable geothermal potential of the mine water depends on the method of pumping, treatment, and discharge. Many reclaimed sites have active water treatment systems for surface pits.[29] Resource sustainability can be evaluated using simulations of long-term system operation based on groundwater and heat transfer models. Even moderate-sized mines can have geothermal potential if a hydrologic regime is appropriate, and the location is favorable.

Information needed for a site evaluation includes the following:

1. Information on the subsurface infrastructure, including boreholes, access points, shafts, and support structures

[29] Personal communication with Mike Korb (Tetra Tech).

2. Type of mining operation and volume excavated, which determines shaft geometry and the volume of void space, such as old coal mines retaining more void space than hard rock mines

3. The depth to underground workings and the maximum mine depth

4. How pumping will affect water flow, temperature, and recharge

5. Suitability of mine water for heating and/or cooling (e.g., temperature, water chemistry, volume)

6. Water quality; poor water quality may require pre- or post-treatment

7. A sufficient and reliable source of water near the site to maximize efficiency

8. Nearby demands for direct heat use in mineral processing, controlling working conditions on site (e.g., ventilation, space heating, cooling), or nearby district heating/cooling

3.4.2 Infrastructure and Access

The location of a mine land site relative to existing infrastructure, such as roads, transmission lines, rail lines, water, and potential off-takers, plays a major role in the technical and economic feasibility of a project. The distance between the source and community/end user for district heating and rights-of-way influence the cost and viability of the application. The mine can have moderate to significant potential when the distance is short (e.g., a few kilometers from the community). For remote or very small mines, the prospect of developing a successful direct use project is unlikely. The rights-of-way for pipelines must be determined during the evaluation phase of the project. Existing rights-of-way will need to be reviewed to determine if existing pipelines are suitable or need a retrofit. For a geothermal power plant, the distance from and access to the power distribution and transmission network and the cost of building this network influence the project feasibility.

If a direct heating application is considered, three parts of the system need to be considered: the primary circuit (mine water is accumulated in a retention tank on mine land), secondary circuit (transports heat to the boiler plant heat pumps [mine water transmits its heat and is discharged into the watercourse], and a backup heat source [e.g., a gas boiler]), and end user infrastructure (the heat produced by the heat pumps is distributed to the individual buildings via the central district heating system). Alternative options could have the retention tank in the secondary circuit or transport it directly to individual heat pumps installed separately at each heated building. Only the circulation pumps and the metering and control of the mine water flows would be in the boiler plant. Bivalent heat pumps at the buildings can be used as a backup. Table 3-1 lists the parameters needed to evaluate the technical feasibility of a system.

Table 3-1. Parameters for a system technical feasibility evaluation

Parameter	Unit
Minimum total volume pumped per pumping period	m^3
Maximum total volume pumped per pumping period	m^3
Minimum pumping period	year
Minimum flow rate	l/s
Maximum flow rate	l/s
Temperature of pumped mine water	°C
Temperature gradient for heat pump	°C/m
Minimum annual production	GJ

Parameter	Unit
Maximum annual production	GJ
Minimum primary circuit output	kWh
Maximum primary circuit output	kWh

3.4.3 Regulatory and Legal Considerations

The regulatory and permitting framework for geothermal resource use on mine land is complex, and it varies depending on the location of the project, the land ownership, and the type of geothermal project envisioned. This section provides a brief summary of some of the steps that a project must follow to meet existing regulations and permitting requirements governing the use of geothermal resources. Notably, these vary by state and site conditions, and they can change with time. This summary does not include additional regulatory and permitting requirements that might be required because of the location of a project on current and former mine land.

High-temperature geothermal resource development regulatory framework

The most evolved set of regulations for geothermal resource development apply to the use of high-temperature geothermal resources for power generation. These regulations have been put in place in many of the western states where commercial geothermal power production projects have been developed. However, these regulations vary from state to state, and depending on whether the project involves federal, state, tribal, or private land.

Geothermal regulatory framework on federal and tribal lands

BLM typically oversees the permitting and regulation of geothermal power projects on federal land. Geothermal resources are governed under the Mineral Leasing Act of 1920, the National Environmental Policy Act of 1969 (NEPA), the Geothermal Steam Act of 1970, the Federal Land Policy and Management Act of 1976, the 1988 Geothermal Steam Act Amendment, the Energy Policy Act of 2005, and the Energy Act of 2020. BLM has developed extensive land use plans for federal lands to balance resource use and protection and to resolve resource conflicts. These plans identify federal lands that are deemed suitable for geothermal leasing. BLM has developed a geothermal programmatic environmental impact statement and has amended 114 regional land use plans to incorporate geothermal leasing (BLM and USFS 2008).

BLM geothermal leasing process is similar to those for oil and gas. Leases are nominated and then entered into a national fluids lease sale system. BLM then checks the land status of the proposed lease blocks, prepares a preliminary parcel list, and has the respective BLM field offices conduct a lease parcel review to check that the sites conform with BLM land use plan. If necessary, BLM will consult with other government agencies and work with stakeholders to resolve any potential issues. If needed, a NEPA review of the site may be conducted. Once all of these checks have been conducted, a lease sale notice that includes prospective parcels with land descriptions and any related stipulations is released, with a period for public comment. BLM then will hold a lease sale online using EnergyNet, with competitive bidding. Parcels that were not bid on as part of the competitive process can then be obtained through a noncompetitive bid process, available on a first-come, first-served basis, with a draw held if multiple requests are received on the first day of this process. BLM leases have a 10 year term, with a maximum lease size of 5,120 acres. The lease will pay rentals on the property until production occurs, and then will pay royalties on production (50% to state, 25% to the county, and 25% to the federal treasury). If a company has a mining claim with patented lands, then that company can obtain a noncompetitive lease for the geothermal resources associated with that property. However, if the company does not apply for this lease, another company can nominate that land for lease, and it would enter into the normal lease sale process, with the highest bidder winning the geothermal lease. The geothermal resource on that land could be developed, but only if it does not interfere with the existing mining operations.

Geothermal exploration and development activities have three phases. In the exploration phase, a company conducts geologic mapping and geophysical surveys and may drill temperature gradient wells. For this phase, the company does not need to have a geothermal lease on the lands being explored. Some of these activities may be deemed as casual use, but no new ground disturbance is allowed without a categorical exclusion ruling. For this phase, a NEPA review is not required. The second phase consists of resource confirmation and requires a NEPA review that covers all operations to be conducted; this review often results in a Finding of No Significant Impacts. Typical activities include drilling of deep wells to establish the presence and characteristics of the geothermal resource; the construction of access roads and well pads and drilling activities all need to be permitted. The final phase is for development and utilization of the geothermal resource. A detailed utilization plan is required to cover the construction of power plants, pipelines, well pads and wells, and roads. This phase also requires a NEPA evaluation. It is unusual that a drilling permit would be denied under this procedure, but stipulations may be placed on drilling and other exploration and development activities because of environmental (e.g., wildlife habitat) or cultural (e.g., archeological site) concerns. Permitting for all geothermal field activities on federal lands is usually conducted by local BLM field offices in concert with any other government agencies that may be involved.

Siting of projects on tribal lands adds an additional set of requirements. Because tribal entities have sovereignty over their territory, approval from tribal governments is required for any geothermal projects to be located on these lands. A number of different statutes and policies relate to geothermal exploration and development activities on tribal lands, including NEPA, the National Historic Preservation Act, the Native American Religious Freedom Act, Executive Order 13007 on Indian Sacred Sites, and the Indian Tribal Energy Development and Self Determination Act of 2005 (BLM and USFS 2009). The Bureau of Indian Affairs is often involved in approving geothermal leases and serves as the federal lead agency under NEPA for projects on tribal land, but some tribes have their own internal regulatory process (Waltner 2009).

Because of the many facets associated with exploring for and developing a geothermal resource, many additional regulatory and permitting agencies will likely be involved in the process that extend beyond NEPA. A wide range of additional regulatory acts often pertain to geothermal projects, such as the Endangered Species Act, the Migratory Bird Treaty Act, the Fish and Wildlife Coordination Act, the National Wilderness Preservation Act, the National Historic Preservation Act, the Wild and Scenic Rivers Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, the Occupational Safety and Health Act, the Clean Air Act (CAA), and the Clean Water Act (Waltner 2009). Laychak (2010) developed a table summarizing the wide array of federal, state, and local agencies that are often involved in different aspects of the permitting and regulatory process. A summary of the potential permits, licenses, consultations, leases, agreements, and certifications involving federal and tribal agencies is presented in Table 3-2. Numerous state, regional, and local agencies also are involved in these regulatory and permitting efforts.

Table 3-2. Potential federal and tribal agencies and organizations involved in geothermal regulatory and permitting activities (adapted from Laychak 2010)

Agency	Role
Advisory Council on Historic Preservation	Impacts on listed historic structures (National Historic Preservation Act)
Army Corps of Engineers	Rivers and Harbors Act and Clean Water Act
Bureau of Indian Affairs	Government to government consultation with tribal authorities
BLM	Rights-of-way (Mineral Leasing Act, Federal Land Policy Act, Energy Policy Act), land leases (Federal Land Policy and Management Act of 1976, Energy Policy Act), exploration, drilling, and construction permits (Geothermal Steam Act, Noise Control Act), and archeological investigations and permits (Antiquities Act)
Department of Defense	Consultation with regulatory agencies and project developers (Energy Policy Act, NEPA), archeological investigations permits (Antiquities Act), and exploration approval (Geothermal Steam Act)
EPA	National pollution discharge elimination system (Clean Water Act), new source review (Clean Air Act), by-product non-toxic certification (Toxic Substance Control Act), hazardous materials and waste handling (Superfund Amendments and Reauthorization Act, Comprehensive Environmental Response, Compensation and Liability Act), and injection well permits (Safe Drinking Water Act)
Federal Aviation Administration	Proposed construction or alteration of objects that may affect navigable airspace
FERC	Transmission lines in national corridors (Energy Policy Act)
US Fish and Wildlife Service	Use in national wildlife refuges (Fish and Wildlife Coordination Act), threatened and endangered species, migratory birds, water resources and quality (Endangered Species Act, Migratory Bird Treaty Act, Fish and Wildlife Coordination Act)
US Forest Service	Special use authorizations and approvals (Mineral Leasing Act, Geothermal Steam Act, National Forest Management Act), and archeological investigations and permits (Antiquities Act)
Lead Agency (often BLM)	Record of decision (NEPA), archeological resource excavation/removal permits (Archeological Resources Protection Act), archeological resources protection (Antiquities Act), and Native American site access (Native American Religious Freedom Act)
National Park Service	Rights-of-way (The Organic Act)
Native American Tribal Governments	Tribal treaties and environmental permits
Native American Tribal Monitors	Consistency with the National Historic Preservation Act
NOAA	Threatened and endangered species (Fish and Wildlife Coordination Act, Endangered Species Act)
OSHA	Construction-related activities

Adapted from Laychak (2010)

Geothermal regulatory framework on state and private lands

The permitting and regulatory framework for geothermal exploration and development activities on state and private land varies on a state-by-state basis. In some states, geothermal resources are considered a water resource, while in others, they are considered a mineral resource, so the state agencies governing the regulation and permitting of geothermal resources vary. In some states, the county in which the project is located also plays a role in permitting and regulatory issues. The environmental review requirements thus vary by state. For example, California has its own California Environmental Quality

Act review process, and geothermal projects larger than 49.9 MWe have a more extensive environmental review overseen by the California Energy Commission.

NREL developed a toolkit that contains a detailed summary of these differing regulatory frameworks for 12 western states (Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming), the RAPID (Regulatory and Permitting Information Desktop) Toolkit.[30] This toolkit consists of a web-based, interactive database with two main tools: (1) a regulatory and permitting database that describes the process for developing geothermal projects in the United States as a whole and in 12 western states; and (2) a NEPA database that catalogued NEPA-related environmental analysis for geothermal projects. BLM and the US Forest Service also generated a comprehensive report (BLM and USFS 2009) that provides an overview of the laws and regulations governing geothermal development in the same 12 western states and provides guidance relating to geothermal resources on tribal lands. In many of the other states not listed here, the regulatory framework for geothermal resources may be incomplete or undeveloped. Young et al. (2019) provided a comprehensive review of nontechnical barriers to geothermal deployment, including the federal and state regulatory framework and the environmental review and permitting process.

For California, several guides have been developed to assist in permitting geothermal projects. Blaydes & Associates (2007) were commissioned by the California Energy Commission to provide a comprehensive guidebook highlighting the different steps involved with permitting a geothermal project in California from the exploration phase until closure of the project. A flow chart illustrating the potential steps involved in this process is shown in Figure 3-12. The report provides much more detailed information on the relevant regulatory agencies and the types of permits and reviews required for each phase of a geothermal project.

[30] https://openei.org/wiki/RAPID

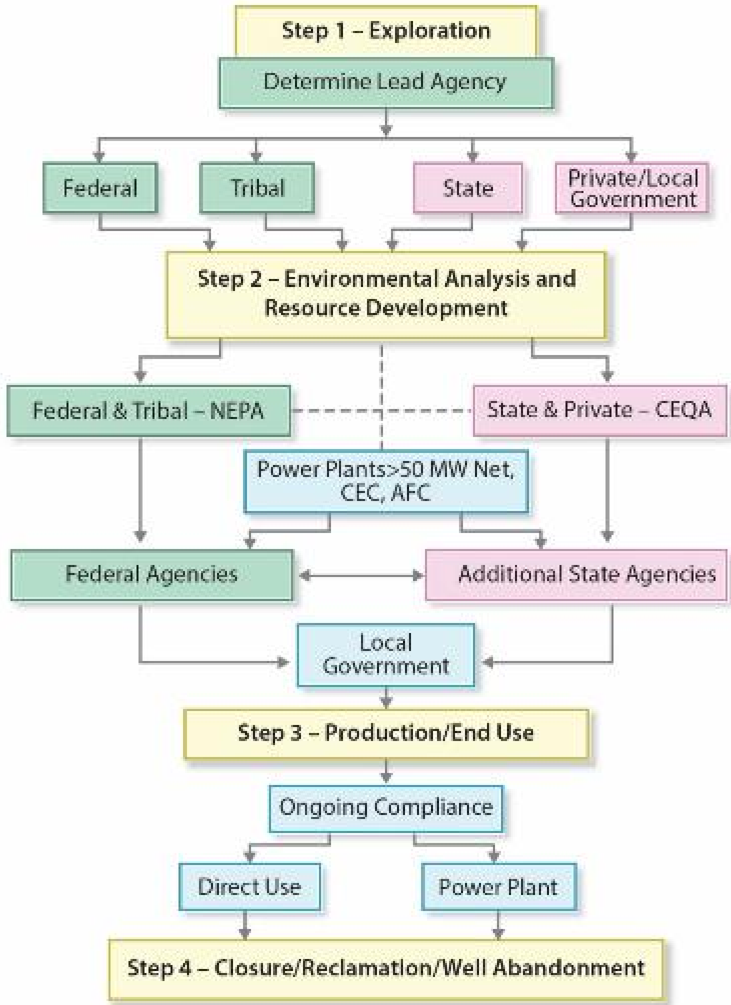


Figure 3-12. Permitting steps of a geothermal project in California (Blaydes and Associates 2007).

The Renewable Energy Action Team—consisting of representatives from the California Energy Commission, California Department of Fish and Game, BLM, and US Fish and Wildlife Service—put together a best management practices and guidance manual for renewable energy projects in California's deserts (REAT 2010). One important aspect mentioned in this report that is relevant to the use of mine land for clean energy projects was the need to evaluate whether abandoned mines may be an important habitat for bats.

Regulatory and permitting framework for geothermal heat pumps

The regulatory and permitting framework for GHPs varies on a state-by-state basis and may be subject to local requirements. There are three main types of GHP systems: horizontal closed-loop systems, vertical closed-loop systems, and open-loop systems. A 1997 EPA report summarized how these systems are regulated by each state (Table 3-3; EPA 1997); these guidelines are likely to have changed since the publication of that report. Horizontal closed-loop systems typically have the fewest permitting requirements because they do not require any drilling. Vertical closed-loop systems typically have permitting requirements that are similar to those of water well drilling and may have additional requirements if chemical additives are contained within the closed-loop network. Open-loop systems may interact with the local aquifers, so these wells typically fall under the guidelines of the federal

Underground Injection Control program, which regulates injection of fluid into the subsurface. Discharge wells for open-loop GHP systems and wells used for closed-loop GHP systems are classified as Class V injection wells by EPA (MDEP 2013). These systems are typically expected to be designed and installed using the best practices guidelines of the International Ground Source Heat Pump Association (IGSHPA 2017). As noted, regulations vary from state to state but often include that boreholes are drilled by a licensed driller, that the wells have set standoff distances from existing water wells, that the wells are completed according to specific standards, that only specific antifreeze additives be used for the closed-loop systems, that the systems have emergency shut-off valves, that a system pressure test be performed prior to starting operations, and that certain decommissioning procedures be followed (MDEP 2013). A permitting decision flow chart for GHP systems in Michigan is shown in Figure 3-14 (Michigan Department of Environmental Quality 2014).

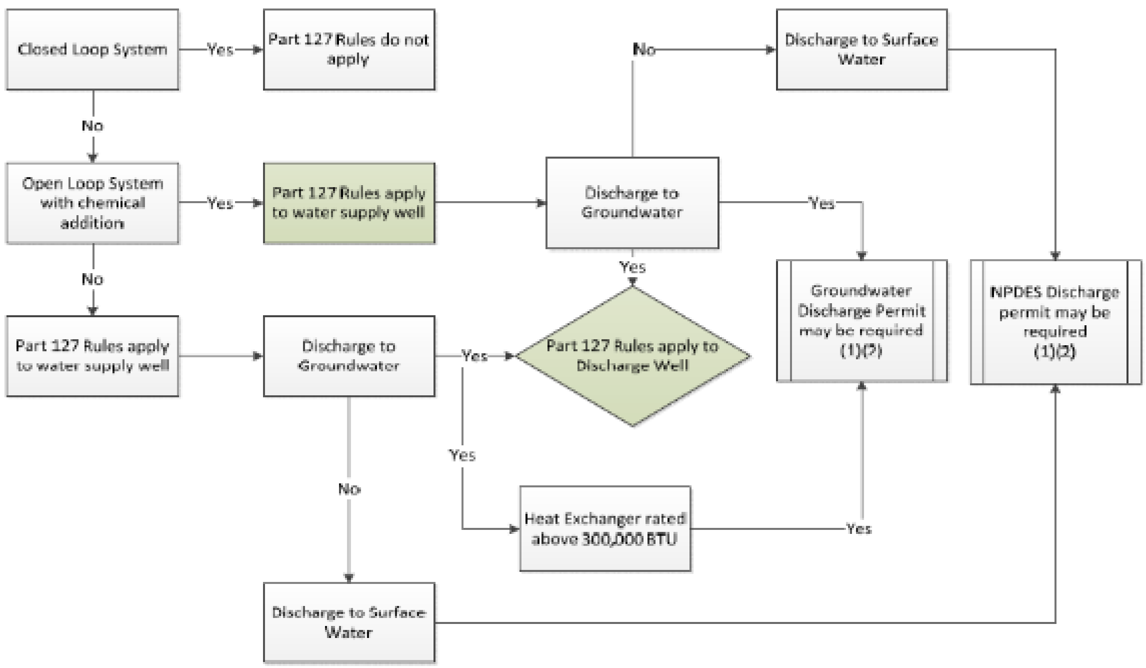


Figure 3-13. Permitting steps for GHP systems in Michigan (Michigan Department of Environmental Quality 2014). This chart is intended only as an example since rules and regulations are subject to change.

The use of a flooded mine for a GHP system may have additional regulatory and permitting requirements (Table 3-3), especially if the water in the mine is deemed to contain hazardous constituents at levels above certain thresholds, such as acid mine water. The level of concern may vary—if the system uses a closed-loop heat exchanger within the flooded mine workings so that water within the mine is not withdrawn, then the risk of contamination is much lower.

Table 3-3. Summary of federal and state regulations for GHP systems

State	Closed systems						Open and closed systems		Open systems		
	Installation				Operation		Installation		Installation		Operation
	Horizontal trench systems	Vertical systems	Specific to grouting	Heat exchanger construction	Heat transfer fluids	Direct exchange systems	Well driller licensing	Pump installer licensing	Water well construction	Injection well construction	Surface water discharge
Alabama							o		o	o	o
Alaska			o						o	o	
Arizona		o	o				o		o		
Arkansas	o	o	o	o	o		o	o	o	o	
California		o					o		o	o	
Colorado		●	●	●	●		o	o	●	o	o
Connecticut		o	o				o	o	o	o	o
Delaware		o	o				o	o	o	o	o
Florida		o					o		o	o	o
Georgia		o					o		o	o	o
Hawaii							o	o	o	o	o
Idaho		o			●		o		o	o	o
Illinois	o	o	o		o		o	o	o	o	o
Indiana		o	o				o		o	o	o
Iowa							o		o	o	o
Kansas		o	o		o		o		o	o	o
Kentucky	o	o					o		o	o	o
Louisiana		o	o	o	o		o		o	o	o
Maine							o	o	o	o	o
Maryland		o	o		o		o		o	o	o
Massachusetts		o					o		o	o	o
Michigan		o					o	o	o	o	o
Minnesota		●	●	●	●		o	o	●	o	o
Mississippi		o	o				o		o	o	o
Missouri	●	●	●	●	●	●	●	●	●	●	●
Montana							o		o	o	o
Nebraska	●	●	o	●	●		o	o	●	●	o
Nevada			o				o		o	o	o
New Hampshire							o	o			o
New Jersey		●	●	●	●	●	o	o	o	o	o
New Mexico		o	o				o		o		o
New York				o		o				o	o
North Carolina		o	o	o	●				o	●	o
North Dakota	●	●			●		o	o	●	o	o
Ohio		●					o				
Oklahoma	o	●	●			●	o	o	●	o	o

State	Closed systems						Open and closed systems		Open systems		
	Installation				Operation		Installation		Installation		Operation
	Horizontal trench systems	Vertical systems	Specific to grouting	Heat exchanger construction	Heat transfer fluids	Direct exchange systems	Well driller licensing	Pump installer licensing	Water well construction	Injection well construction	Surface water discharge
Oregon							o			o	o
Pennsylvania							o	o	o	o	o
Rhode Island							o	o	o	o	o
South Carolina		o					o		o		
South Dakota	●						o		o	o	o
Tennessee		o	o				o	o	o	o	
Texas		o	o				o		o	o	
Utah		o	o				o		o	o	o
Vermont		●	o		●	o	o	o	o	o	o
Virginia		●	o	o		o	o	o	o	o	o
Washington		o					o		o	o	o
West Virginia							o		o	o	o
Wisconsin		●	o	o	o	o	o	o	o	o	o
Wyoming	●	●	o		●						o

EPA (1997). o Existing water well regulations are applied. ● Specific GHP regulations are applied.

3.4.4 Decommissioning Considerations

The decommissioning of GSHP systems is straightforward. Old units can be dismantled, and certain components recycled, pipelines can be removed at the end of life, and wells can be sealed. If water quality is poor, then contingency plans for surface mine water disposal need to be developed and included in project design and evaluation.

Decommissioning of a geothermal field is a more complex process. Wells need to be plugged and abandoned according to applicable regulations, and existing surface infrastructure (wellheads, well pads, pipelines, power plants, and transmission lines) needs to be removed and the land restored. Projects may need to be bonded to ensure that adequate funds are available to cover the decommissioning costs at the end of a project.

3.4.5 Economic Considerations

The project economics will depend on a variety of factors but especially the prevailing energy market prices and LCOE for the proposed geothermal project. Geothermal power generation projects have a number of defined steps (Gehringer and Loksha 2012), each with different costs and project risks (Figure 3-14). The pre-drilling exploration phases of the project are considered high-risk but have relatively low costs. Exploration drilling, which is needed to confirm the presence of a geothermal resource, has elevated costs and relatively high risk. Once the presence of a resource has been validated by drilling, the project then focuses on establishing the size of the resource through confirmation drilling. If a project is deemed to be economically viable and financing is obtained (usually after signing a PPA), then drilling of production and injection wells and construction of the power plant and pipelines proceeds, followed by plant startup and operations. In addition to installation costs, O&M costs, decommissioning costs, and costs of contingency plans, other factors such as advances in heat pump technology, GHG reduction, ongoing water treatment costs, and competition from less expensive alternative energy sources need to be considered, as well.

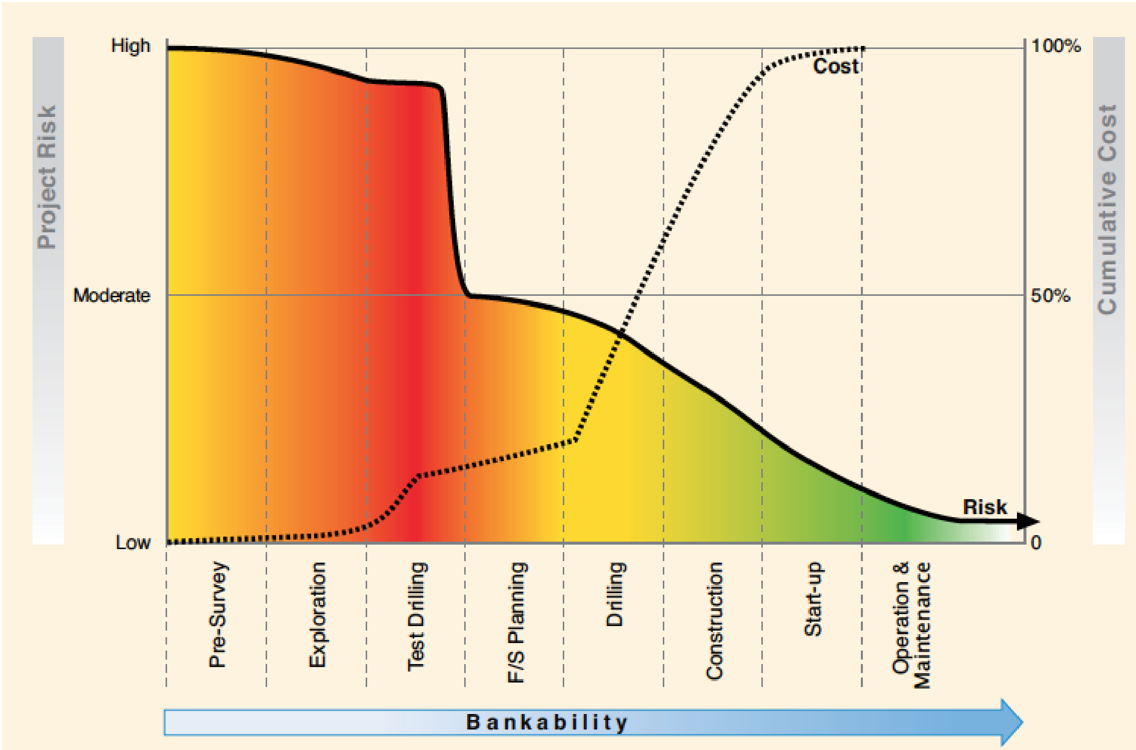


Figure 3-14. Project cost and risk profile at different development stages (Gehringer and Loksha 2012).

Several tools can be used to estimate the costs and LCOE of a project. One of these is the GETEM (Geothermal Electricity Technology Evaluation Model) (Mines 2016), which can be used to calculate LCOE for both hydrothermal and EGS power projects. The user inputs the resource temperature and the depth to the reservoir (constraining the well depth). GETEM uses a number of default inputs that can be modified if appropriate; Table 3-4 depicts a few of the default parameters used to estimate the plant output and type, project step duration, and discount rates. In addition, flow rates (kg/s) and production/injection ratio are needed for defining a scenario.

Table 3-4. Example default values used in GETEM (Mines 2016)

Power sales*			
Resource temperature	**Resource type**	**Plant type**	**Sales**
<140°C	Hydrothermal	AC binary	10 MW
<175°C	Hydrothermal	AC binary	15 MW
≥175°C	Hydrothermal	AC binary	30 MW
<250°C	Hydrothermal	Flash steam	30 MW
≥250°C	Hydrothermal	Flash steam	40 MW
<140°C	EGS	AC binary	10 MW
<175°C	EGS	AC binary	15 MW
≥175°C	EGS	AC binary	20 MW
<250°C	EGS	Flash steam	25 MW
≥250°C	EGS	Flash steam	30 MW

Project duration and discount rates		
Phase	**Duration**	**Discount rate**
Exploration permitting	1 year	30%
Exploration	2 years (hydrothermal) 1 year (EGS)	30%
Confirmation	1.5 years	30%
Permit for plant and field	1 year	15%
Complete well field	1.5 years (hydrothermal) 2 years (EGS)	15%
Power plant	2 years (binary) 1.5 years (flash)	7%
Operation	30 years (hydrothermal) 20 years (EGS)	7%

*Default values are based on resource temperature and resource type.

GETEM generates an LCOE for the overall project based on the input values and the cost assumptions of the model. The inputs (both from the user and those included in the tool) must be realistic based on the specific constraints of the project and the existing economic situation.

Researchers at Pacific Northwest National Laboratory developed MAGE (Model for Analysis of Geothermal Economics) to estimate the financial viability of geothermal projects (Goodman et al. 2022). This model uses a series of input parameters, similar to GETEM, to evaluate the cumulative discounted NPV of a geothermal development project over time (through the exploration, construction, and operational phases of the project) to estimate the LCOE and how long the payback period will be (Figure 3-15). This model can be used to evaluate how changes in capital costs, discount rate, and the project timeline influence the project LCOE. Wall et al. (2017) also noted that the project risk greatly impacts the cost of capital needed to finance a project, thus impacting the weighted average cost of capital of a geothermal power project. Economic tools such as MAGE can be used to assess the financial viability of a geothermal project on mine land, and they allow for comparison with other types of clean energy development options. Furthermore, other aspects such as the high-capacity factor of geothermal systems should be considered when assessing the overall value of geothermal energy to a specific project. Some mine sites are in remote locations, so other energy options may be restricted and expensive. In addition, many mining companies have adopted new corporate sustainability standards that encourage the development and use of clean energy for their mining operations (e.g., Reyes et al. 2011). Thus, multiple factors need to be considered when evaluating the viability of geothermal energy projects at or near mining sites.

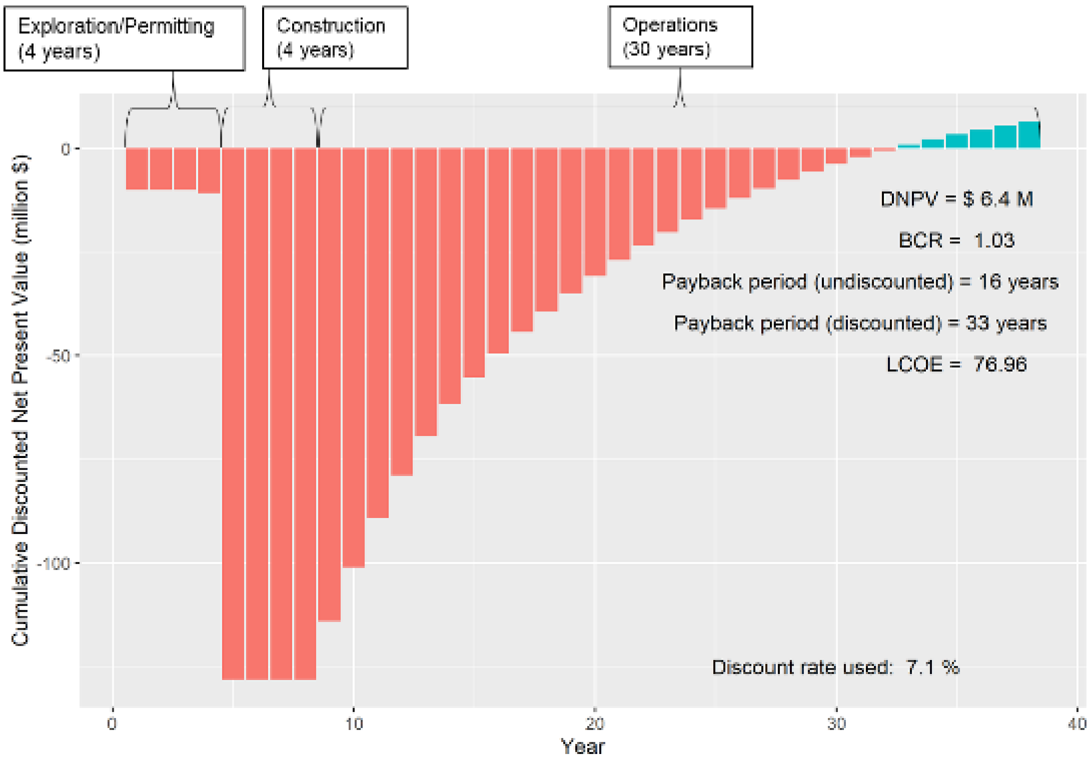


Figure 3-15. Example of baseline MAGE output for a hypothetical geothermal development project (Goodman et al. 2022).

Project risk is also important to consider for a direct use geothermal development on mine land. Insufficient information about abandoned subsurface mines can result in a high upfront risk that translates into high capital costs (e.g., drilling wells to delineate the resource). Using engineered features associated with mine sites, where the capital and operational costs are already committed, is a clear opportunity to exploit geothermal heat energy. The existence and possible use of the existing central district heating boiler plant and the distribution network would lower overall project costs. In some cases, retrofitting existing infrastructure or backup equipment for energy recovery might be necessary.

Capital investments include the following:

- Heat pumps
- Pipeline from the source to the boiler plant
- Pipeline from the boiler plant to the buildings
- Circulation pumps
- Heat exchanger in the boiler plant
- Measurements and controls
- Boiler plant
- Surface or underground storage tank

Depending on the reservoir properties, capacity of the heat source, end user location, and heating requirements, the location and type of these components may vary (e.g., the capacity and type of the heat exchanger and heat pumps).

MWG systems require an initial investment (in capital costs) of designing and emplacing a geothermal system, which needs to be offset by long-term operational cost savings of MWG. Cost savings come from lower maintenance costs, reduced fuel import, and the ability to use existing infrastructure. Compared with other GHP systems, MWG systems can benefit from constant temperature and water availability for recirculation. The use of mine water for heating can represent a sustainable use of current and former mine land and support economic development in locations previously supported by mining activities. Key risks encountered by MWG schemes include clogging of system components with mineral precipitates (e.g., Fe oxides and hydroxides), uncertainty in targeting open mine voids and their hydraulic behavior, uncertainty regarding longevity of access to mine water resources, and accumulated ongoing monitoring and maintenance burdens (Walls et al. 2021).

Based on end users' heat consumption statistical data, an average heat consumption per year can be calculated. An average monthly heat consumption depends on the season, whereas hourly needs depend on the instantaneous outdoor temperature. If production cannot be adjusted based on actual needs, significant energy and financial losses can be expected, especially in months when demand for heat is minimal. Table 3-5 lists the main input parameters needed for an economic model evaluation. The coefficient of performance is used to quantify heat pump efficiency. The smaller the difference between the inlet and output temperatures, the higher pump efficiency, as less energy is required to reach heating or cooling needs.

Table 3-5. Main input parameters needed for an economic model evaluation

Parameter	Unit
Input power of the heat pump	kWe
Heating output of the heat pump	kWe
Coefficient of performance	—
Coefficient of available output of the heat pump	%
Annual heat pump operation time	h
Minimum annual production with heat pump	GJ
Operational efficiency	%
Average heat consumption	GJ/year
Backup option (gas boiler, bivalent heat pump) cost	$

Oppelt et al. (2022) researched existing and planned mines and reported that the five largest ones have a maximum heating load of approximately 0.9 to 11 MW. They also reported that MWG energy is less expensive to operate than fossil fuels; labor costs could be below $0.06/kWh, and CO_2 emissions can be reduced by at least 56% compared with fossil fuels.

3.4.6 Social Considerations

Ensuring that a project has a minimal impact on communities is essential for project success. Information on economic development and the demographic and social context is provided in the US Census Bureau database. Data obtained from economic and regulatory databases or other references are important in understanding project risks and benefits. Furthermore, understanding land use history and environmental sensitivities is critical. Social license is an integral part of any mine's sustainable development plan and includes the importance of the operator's in-house green energy culture and policy and the option for local communities to use the produced energy. In the post-closure phase, hot water irrigation can enhance reclamation rates, or geothermal district heating can support job creation.

Stakeholder outreach is a key component of every geothermal development project (e.g., a high-temperature power generation project, a low-temperature district heating system). For social acceptance of a project, it is important to communicate the potential project impact on communities, including water, land, and energy usage, as well as economic and job implications with local community. The project developers must be in regular contact with the local communities, regulatory and permitting groups, and other interested parties from the outset of a project. Such interaction helps identify what is important to the different stakeholder groups, allows for their concerns to be registered and addressed by the project, and can result in public acceptance and support. Robertson-Tait et al. (2018) described different types of outreach and engagement activities for a specific project, and Otero (2015) described outreach strategies that have been employed by different groups in Chile to familiarize the public with geothermal energy.

3.5 CARBON CAPTURE, UTILIZATION, AND SEQUESTRATION, AND DIRECT AIR CAPTURE

3.5.1 Physical Site Characteristics

3.5.1.1 Land area

For mines with power plants located on-site, some physical footprint is necessary for the capture equipment, CO_2 storage, and storage of consumables (Table 3-6). Storage of material supplies will depend on the type of capture system employed. A majority of the land footprint associated with DAC systems is simply the spacing required to ensure 400 ppm concentrations at each air contactor. It is possible that only 5%–10% of the land footprint associated with DAC is physical equipment (excluding land for energy systems).

Table 3-6. Summary of minimum land area required by carbon sequestration technologies

Technology	Surface footprint scaling parameters	Area of 1 MT CO_2/y (km^2)
Capture		
From power plant (solvent)	Capture rate and on-site storage	Expected to use land within facility
Solvent DAC	Capture rate, energy source	0.05–0.4 (1 total)
Sorbent DAC	Capture rate, energy source	0.062–0.6 (1 total)
Mineralization of tailings and rock from air	Material carbon removal potential, dissolution rate (particle size), application rate	20–75
Transport		
Pipelines	Distance, diameter, right-of-way	0.00015–0.01
Sequestration		
Geologic formation	By well pad	0.9–2.8
Mineralization from concentrated stream	Mine tailing container	Expected to use land within facility

The right-of-way width for pipelines is typically 15.25–30.5 m, and pipelines per source can span a few to hundreds of kilometers. For clustered sources, the total pipeline distance can be up to thousands of kilometers, but per source, it could be less than 1,000. Avoiding rugged terrain, populous areas, rivers, and marshes and wetlands can minimize costs but increase distance (DOE-NETL 2017a).

The land footprint for geologic sequestration consists primarily of well pads. The well pads are sized to the drill rig, whose size is based on the diameter and depth of the well. Example projects include the

Decatur Site (1,000 MT/day injection into sandstone formation), with a pad of 200 × 150 ft (2,787 m^2), and the SECARB Black Warrior Site (test injection into coal seam), which has a pad of 100 × 100 ft (929 m^2) (DOE-NETL 2017b). If the project requires producing water for pressure management, additional pads are necessary for production wells, and additional land is needed for disposal wells and/or water treatment. One of the current handful of commercial-size projects injecting only for sequestration without oil recovery includes pressure management by brine extraction at Chevron's Gorgon in Australia. The substantial cost increase this method incurs makes it unlikely to be a feature of many projects in the near term unless it provides an economic co-benefit, which may come from tax incentives such as those provided by the Inflation Reduction Act or carbon credits.

Not much has been reported about the physical space required for DAC systems. A solvent system is estimated to have a 0.055 km^2 footprint per 1 MT/year of captured CO_2 because of the contact area requirement (Socolow et al. 2011). Climeworks estimates are per net metric gigaton of CO_2 captured (Beuttler et al. 2019), which is an amount similar to the prior estimate measured in 1 MT/year. Another report suggests land requirements may vary from 0.4 to 0.5 km^2 per 1 MT/year. The low end of this range is a value reported for solvent by Carbon Engineering (Lebling et al. 2022). This range is an order of magnitude larger than the estimates previously cited. A 1 MT/year DAC plant coupled with geothermal power is estimated to have the smallest land footprint, with only 7 km^2 required for the geothermal system. In contrast, Climeworks estimates that almost 2,000 km^2 of land is needed for solar PV to power a metric gigatons per year (2 km^2 per MT/year) of net CO_2 capture for a solid sorbent–based system, including the space for solar PV. The DAC system itself only has an estimated footprint of 62 km^2. Presently, DAC systems based on solid adsorbents are under development for relatively dry ambient air conditions. It is worth noting that the performance of DAC systems can vary considerably with climate and weather.

The treatment of mine tailings with captured CO_2 or with ambient air are expected to be performed on-site at the location of waste storage and disposal. The mineralization project occurring in San Benito County, California, at the King City Asbestos Corporation Joe Pit mine will demonstrate methods for mineralization with ambient air and serpentine rock waste. Capture from ambient air will likely require land application or additional infrastructure for exposing mine tailings to air and thus will have a larger land footprint than if mine tailings were used for CO_2 sequestration from a concentrated stream. In cases where mine tailings are suitable for land disposal for EW, the availability of local cropland, rangeland, marginal land, or reclaimed fields would be key for consideration. Soils for the disposal of mine tailings for EW cannot have a history of alkalinity issues because these issues would only be exacerbated. Acidified soils and soils that are level for easy tractor distribution are ideal. The land area required for land distribution of alkaline waste depends on the rate of application and the target depth of application. Mine tailings that are powdery (bulk density of 1,800 kg/m^3) have been applied at rates between 45 and 200 MT/acre in pilot projects. The CO_2 capture potential of the material varies, but for the most reactive materials such as brucite (1.2 MT CO_2 reduction per MT of material), this rate translates to 54 to 240 t CO_2 reduced per acre. For 1 MT of CDR, this may require between 20 and 75 km^2 of land. Reaching a material's full capture potential takes years to hundreds of years depending on the size of the material, which influences dissolution rates (Hangx and Spiers 2009). Assuming materials are <10 µm, regular applications of materials on the same land will ultimately reach a steady state of capture per area. Far more land will be required if only a single application is possible.

3.5.1.2 Geology

DOE has published best practices on geologic sequestration projects, including site screening, selection, and characterization. Numerous development-phase projects for geologic sequestration in saline formations and enhanced oil recovery formations offer insights into formation potential and suitability.

Five types of geologic reservoirs have been studied: saline water reservoirs, oil, and NG reservoirs, unminable coal seams, organic-rich shales, and basalts.

The advantage of oil and gas reservoirs is the amount of data available to characterize and screen sites, as well as the potential availability of infrastructure and wells, although new permits would be required. Although fewer data exists for saline reservoirs, their expansive coverage of the United States gives them more than an order of magnitude greater capacity in total and generally places them in closer proximity to large potential point sources. Pressure increases limitations, which are in place to avoid nuisance or damaging induced seismicity and other effects such as fracturing of caprock, are likely to be greater constraints to sequestration in saline than oil and gas reservoirs owing to the pore space previously voided in gas reservoirs by prior production.

In coal seams, CO_2 replaces CH_4 on the pore surface of coal by way of adsorption. The production of CH_4 in the process is possible, although more research is necessary to understand the characteristics that make a coal seam viable for long-duration CO_2 storage. Coal mines and coal seams could be used for enhanced geothermal energy production by injecting cool water, letting the water heat to the conditions at depth, and extracting the water. This may be a conflicting use of coal mines unless operating at more shallow levels than what would be necessary for CO_2 sequestration.

Basalt reacts relatively rapidly with CO_2 in the presence of water, potentially trapping CO_2 permanently through mineralization (e.g., Gislason and Oelkers 2014). Areas of research include understanding the rates of this process and the means of leveraging the full storage capacity of such a reservoir without loss because of leakage prior to mineralization and possible reductions in injectivity and permeability.

Geologic suitability includes available prospective storage, including planned volume and shared volume (multi-project formation) for injection over the geologic storage project lifespan. For saline formations, having suitable rock facies for controlled flow of CO_2 is important. An adequate formation depth of 800 m or more is necessary to keep CO_2 in a supercritical state. In the United States, five saline and four enhanced oil recovery CO_2 storage projects are in states of development or operation.

Geologic sequestration project development generally progresses from finding potential subregions and giving approval for development to qualified sites to active injection and postinjection. At the potential subregion level, a significant amount of screening and site selection is still necessary. At the qualified site level, the evaluation process largely consists of further site characterization. Guidelines are available for all stages of site evaluation.

3.5.1.3 Environmental sensitivities

Many of the technologies being considered for carbon management, including DAC and CCUS, are still in early stages of deployment. Data are limited on the potential effects of CCUS projects on sensitive ecosystems and species. Aspects of projects that are related to mineral handling and transportation as well as road development, site construction, well injection, and water production and treatment, if needed, will fall under established local, state, and national regulations. Wetlands are regulated under the Clean Water Act, with Section 404 covering any discharge into or disturbance of US waters, including wetlands. In some cases, development in or near wetlands, including transportation, may require that alternative wetlands be set aside. Construction of roads must meet standards and regulations to avoid excess erosion, site disturbance, fugitive emissions, and dust. Construction proximity to sensitive environments and natural ground waters should be avoided.

Ultimately, a DAC system must move a large volume of air to capture meaningful amounts of CO_2. A large-scale system may move thousands of metric tons of air per hour, and potential impacts on local wildlife (Caskie 2020) would need to be understood.

Constructing a new well pad for a geologic sequestration project will include leveling the ground and stockpiling topsoil for later use as well as possibly grading the area for water holding ponds, where drilling fluids can be stored. Minimal produced fluids may be from advancing a boring for a sequestration well and then constructing and developing the well, unlike for hydraulic fracturing of source rock and similar low-permeability geologic materials. Retention of precipitation on the pad is minor compared to the other volumes. Oil and gas projects have been successfully deployed near populous areas or in areas with protected wildlife, although the challenges of permitting and access to rights-of-way may lead to increased costs. Injection wells for sequestering CO_2 would be subject to EPA regulations, which currently require Class VI wells to follow specific regulatory and permitting guidelines under the Safe Drinking Water Act (EPA 2018).

Soils for the disposal of mine tailings for EW cannot have a history of alkalinity issues because this issue would only be exacerbated. Acidified soils and soils that are level for easy tractor distribution are ideal. The growth of biomass may increase as a result of rock dust application; however, decreased uptake of Ca is possible (Ten Berge et al. 2012). The transport of mine tailings and rock waste may present a hazard owing to dust creation and the presence of metals or potential asbestos contamination. The potential effect of metals released on soils receiving materials to mineralize is also a current concern with little research. Additionally, the composition of runoff water or leaching water from mine tailings treated on-site should be monitored.

3.5.1.4 Other resource potential

At some geologic storage sites, substantial amounts of brine waters may be produced to manage pressure increases in the reservoir. These brine waters may be of interest for resource or geothermal heat extraction (Breunig et al. 2013), as mentioned earlier. Although this use is theoretical, desalination of produced waters could generate potable water, and the brine could be further processed to generate salts, boron, Mg, Ca, potassium, and in some cases, REEs, which may provide ancillary benefits to these projects.

Brines are common formation fluids in sedimentary basins (e.g., White 1965). The disposal of coproduced brines associated with unconventional oil resources is a major challenge, and the use of saltwater injection wells to dispose of the large volumes of brines being produced has led to significant levels of induced seismicity (e.g., Ellsworth 2013, McGarr 2014). One alternative to disposal is to find other uses for the brines. Some of the dissolved mineral components of these brines may have commercial value if they can be recovered in an economically viable and environmentally responsible manner. Breunig et al. (2013) evaluated the potential for recovering mineral constituents such as Na, Ca, Mg, potassium, and boron from brines contained in the Vedder Formation (San Joaquin Basin, California), the Jasper Formation (Gulf Coast Basin, Texas), and the Mt. Simon Formation (Illinois Basin, Illinois). They noted a wide range in the potential economic value for each of these brines, given that they varied significantly in total dissolved solids contents and thus in the amounts of these mineral constituents that could be recovered. The commercial value of these brines will depend in part on the technical feasibility and recovery factors for removing these constituents, the concentrations of these components in the brines, and the commodity values of these materials, which vary based on market conditions.

USGS has created a geochemical database of brine compositions produced from sedimentary basins across the United States, containing analyses of over 100,000 produced and deep formation water samples (Blondes et al. 2019). Quillinan et al. (2018) report the REE concentrations and other major and minor element constituents of oil- and gas-produced waters from the Wind River, Powder River, Green River, and Washakie basins in Wyoming and brine samples from the Kevin Dome area in Montana. They also summarize USGS analyses from the Appalachian, Permian, and Williston basins. Although these brines generally had low REE concentrations (which is the focus of this study), a number of the brine samples from the Williston Basin had elevated boron (>500 ppm) and Li (>50 ppm) concentrations.

Several projects have reportedly recovered Li from brines in sedimentary basins in the United States (Figure 3-16). Standard Lithium is involved with two projects (Worley 2019, NORAM Engineering and Constructors Ltd. 2021) focused on recovering Li from brines from the Smackover Formation in Arkansas, which contains elevated Li concentrations (average value of 174 mg/L; Collins 1974). The Smackover brines have a history of being used for Br production and contribute to approximately 40% of Br production globally (the average Br content is reported to be 3,126 mg/L; Collins 1974). A group that operates water treatment plants for coproduced brine from the Marcellus Shale in Pennsylvania developed a pilot project to extract Li from the brine (Marcellus Drilling News 2019). Reported Li concentrations in produced formation waters from the Marcellus range from 18 to 233 mg/L (Phan et al. 2016). Thus, significant potential exists for extracting Li and other mineral constituents from saline formation waters from sedimentary basins where geologic carbon sequestration may occur.

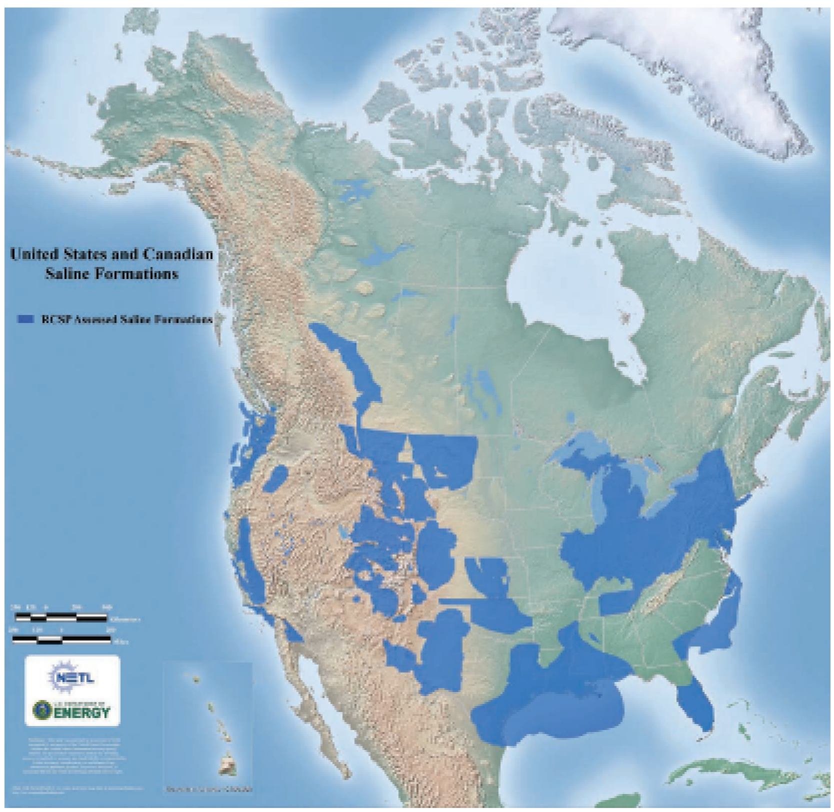


Figure 3-16. Locations of identified saline formations in sedimentary basins within the United States and Canada that could potentially host geologic sequestration of CO_2 (DOE-NETL 2010).

3.5.1.5 Other site characteristics

The existence of faults will need to be carefully understood because faults will affect how the CO_2 injection zone is compartmentalized. Large-scale CO_2 injection into subsurface reservoirs could result in induced seismicity (Zoback and Gorelick 2012). Coal seams may generate CH_4 as CO_2 is injected and preferentially adsorbs. Water availability is another important factor.

3.5.2 Infrastructure Access

3.5.2.1 Transmission

Energy requirements for DAC can be estimated from technoeconomic reports on leading approaches, and the energy requirements largely consist of heat demand (80%) followed by electricity demand (20%). Transmission lines will be required to power DAC and CO_2 compression and pipeline pumping if local renewable distributed energy systems are not available. NG will be required for solvent DAC systems because temperatures up to 900°C are necessary for CO_2 recovery, although other possible methods include methods for electrochemical reactions that only require electricity. A NG system can also provide necessary electricity and heat, with exhaust gas being sent to the CO_2 adsorber in systems like the one from Carbon Engineering. Using the Carbon Engineering system as a prototypical solvent-based DAC, between 5 and 9 GJ of NG and 366 kWh of electricity are required for every metric ton of CO_2 removed from the atmosphere. A humidity swing adsorption system requires 61 kWh/MT CO_2 for fans with flow rates of 4,451 MT/h of air. Climeworks and Global Thermostat, which use solid adsorbents, have thermal energy needs between 80°C and 120°C, which align nicely with geothermal energy. Climeworks has demonstrated integration with geothermal and waste heat energy sources.

3.5.2.2 Roads

Road access will be critical to deliver materials for construction and operation for capture. Ideally, road access for maintaining and monitoring pipelines and injection points will be available, with the heaviest usage likely during construction (DOE-NETL 2017b). A key component of site preparation for geologic storage includes establishing site security and access. Access for monitoring and verification is necessary. Access for this purpose involves periodically evaluating pressure and monitoring for leaks. The monitoring schedule may be every 1, 2, 4, or 10 years for oil and gas fields and every 5 or 10 years for saline formations. Formations are estimated to operate for 30 years, which will require access to electricity and equipment (Vidas et al. 2012) for repair and replacement.

Multiple trucks will be necessary to transport mine waste to nearby land for EW. A typical solids truck payload can be 14.5 MT. However, large B-train trucks can transport 50.7 MT, which is up to the road limit (70 MT) after subtracting the truck's own empty weight of 19.3 MT.

3.5.2.3 Rail

Roughly 85% of coal is transported by rail, with the remaining amount transported by barge or truck. Transport by rail allows coal to be moved from the mines to power plants (EIA 2011). If rail could be repurposed for CO_2 transport, pipelines would possibly not need to be constructed. Emerging concepts for transporting CO_2 using a material that could be loaded on a rail system may be compelling (Breunig et al. 2022).

3.5.2.4 Pipeline/right-of-way

Transportation of captured CO_2 is assumed to be by pipeline and will be a major cost of a CCUS project. Numerous models and approaches estimate compression, recompression, and pipe sizing for CO_2 transport. Pipelines for CO_2 comprise three types of pipelines: gathering lines, trunklines, and distribution lines. Distribution lines are the pipes that ultimately take CO_2 to storage fields and wellheads. Distance, ambient pressure, flow rates, and sizing of pipes to fit flow rates all affect the pressure drop. Large-scale pipelines tend to be supercritical, in which CO_2 is compressed to 150 bar at 40°C, with recompression necessary to maintain that state. Recompression for sequestration into a geologic formation is also necessary because injection pressures have been reported at 15 MPa. Compression equipment and energy requirements vary by design, but recent reports on DAC systems propose using glycol systems for dehydration and centrifugal compressors with multiple incremental stages (anywhere from 2 to 8) with intercooling (Keith et al. 2018). Dehydration is important to reduce corrosion from H_2CO_3 and water buildup. Reciprocating compressors are best suited for smaller flow rates of CO_2. Booster pumps are used to inject CO_2 into a formation, and when designed to do so, they operate to keep the net positive suction head well above the vapor pressure of liquid CO_2. For areas that experience large seasonal changes in ambient temperatures, insulation will be necessary to minimize fluctuations.

Rights-of-way for CO_2 pipelines must be determined during project screening phases. Existing rights-of-way for CO_2 pipelines will need to be reviewed for their capacity and age. However, these existing rights-of-way will be valuable for moving a project forward. Pipelines not for CO_2 may have rights-of-way that can be leveraged, although the full retrofit of an existing pipeline may not be feasible.

3.5.2.5 Water

Between 1 and 7 MT of water are required for solvent systems such as that used by Carbon Engineering (Keith et al. 2018). Water is lost through evaporation, which will be higher in arid, hot locations. In DAC systems that use a solid sorbent, CO_2 is recovered from the material using either a temperature or humidity swing. Climeworks uses a temperature swing approach. The humidity swing approach is used by Klaus Lackner. When steam is used to regenerate the sorbent material, approximately 1.6 t of water is required per metric ton of CO_2 captured (Board and NASEM 2019). If indirect heating is used, some water may actually be produced because water can coadsorb with CO_2 (0.8–2 MT water/MT CO_2 captured) (Fasihi et al. 2019). Emerging concepts for capture without the need for water are emerging, but the availability of water may be an important consideration in the deployment of DAC.

EW can occur as a gas–solid reaction or in aqueous solution. Gas–solid reactions occur under extreme conditions with steam. In aqueous environments, CO_2 dissolves into water, leading divalent metals to release and carbonate products to precipitate. For example, the weathering of limestone to bicarbonates is as follows:

$$\mathrm{CaMg(CO_3)_2(s) + 2CO_2(g) + 2H_2O(l) \rightarrow Ca(HCO_3)_2(s) + Mg(HCO_3)_2(s)}$$

Mine tailing piles may already be saturated with water from precipitation depending on the method of storage. In some cases, pretreatment of the materials may lead to drying, in which case water may be necessary in subsequent stages. If water is injected into the mine tailings, a geothermal or solar thermal system could possibly heat the water to enhance reaction rates, although the benefits of this are poorly understood (Stokreef et al. 2022). The pilot test at the King City Asbestos Corporation Joe Pit mine is monitoring water cycling.

3.5.2.6 Other infrastructure

Other infrastructure that would be synergistic with a Carbon Engineering system include the following (Keith et al. 2018):

- Sources of $CaCO_3$ or CaO for pellets to be used in the pellet reactor.
- Equipment from cooling towers that could be repurposed for a DAC contactor, such as fans, structured packing, demisters, fluid distribution systems, and fiber-reinforced plastic structures.
- An air separation unit that produces oxygen. A system producing 30 kt/day is necessary for a facility capturing 0.98 MT CO_2/year.
- Pellet reactor, which may be recycled from wastewater treatment equipment.

- Calciners, which are large steel vessels lined with refractory brick, and heat recovery cyclones.

- Steam slaker, which is a refractory lined fluid bed that slakes quicklime (CaO) to $Ca(OH)_2$.

In the case of geologic storage projects, valuable infrastructure will include the availability of drilling rig and well pad components, monitoring equipment, and wastewater injection disposal wells or management infrastructure (i.e., evaporation and collection ponds, off-site commercial treatment). Other shared infrastructure may include equipment for enclosing work areas to limit access and surveillance equipment. Well drilling and operation involves safety hazards, and only essential personnel should be in the work area.

3.5.2.7 Infrastructure upgrade cost and potential

For MEA post-combustion capture technology, material flows and an energy penalty are associated, which leads to increased coal consumption per megawatt hour of energy production from the power plant. Material flows include the amine solvent (MEA), limestone for flue gas desulfurization, and NH_3 for catalytic reduction.

3.5.3 Regulatory and Legal Considerations

Key in the selection of a site for geologic storage is the ability for the storage to be permitted under all relevant regulations. This permission also includes obtaining rights to subsurface and surface area for facilities, pipelines, and CO_2 storage. A risk assessment ranging from public acceptance, liability, and financing is also critical for geologic storage projects to move forward.

Key to the deployment of CCUS projects is policy support in the form of carbon pricing or other funding methods. Funding mechanism 26 USC 45Q applies a tax rebate depending on the type of capture and storage (saline or enhanced oil recovery). This code provides \$60/t CO_2 for enhanced oil recovery storage and \$85/t CO_2 for non–enhanced oil recovery formations. An added \$180/t is applied for DAC projects.

Regulations covering sensitive species and environments were discussed in Section 3.5.1.3. Emissions of NaOH from solvent DAC systems will need to meet regulatory limits. The solvent system also uses KOH, which is hazardous to humans and will be monitored to stop exhaust to the atmosphere. EW projects that will apply materials to soils will have to meet regulations. For example, in California, regional water boards regulate mining waste discharge. Native American tribal lands may require additional measures of protection or may be excluded altogether from sites. Federal funds will trigger NEPA requirements, which covers regulatory and environmental protection factors.

3.5.4 Decommissioning Considerations

The decommissioning of DAC systems is expected to be relatively straightforward because all components are modular. Pipelines can also be removed at their end of life, and wells can be sealed. Monitoring of geologic storage projects may require that sensor equipment and access roads remain in place.

3.5.5 Economic Considerations

The capture of CO_2 at a power plant will likely require dedicated full-time and part-time employees. The capture system will be powered by the facility itself. In the case of DAC systems, dedicated labor will also be necessary. In 2020, Climeworks reported 70 FTE positions over 14 DAC plants. The cost of CO_2 capture is significantly affected by the price of electricity and thermal energy, as well as the carbon intensity of the energy source. The cost of EW of mine tailings is unclear, aside from truck fleet costs for transporting materials to soils, or the need for equipment for pretreating rock waste and mine tailings. If rock waste materials are too course, they do not have the necessary surface area to react with CO_2, and comminution equipment such as ball mills may be necessary. If CO_2 is injected into the mine tailing, a compression system and cover system may be necessary to isolate the system. The cost of electricity will greatly affect the viability of any CCUS technology requiring compressors—particularly pipelines and injection wells.

Reliability of the CO_2 source is key to avoiding shutdown and restarts of the injection site. An example of a project affected by unexpected CO_2 supply changes is the Farnsworth Unit CO_2 enhanced oil recovery project in Texas, where CO_2 is delivered from an ethanol plant in Kansas and a fertilizer plant in Texas (DOE-NETL 2017a).

3.5.6 Social Considerations

The US Census Bureau offers information on state economic development and the demographic and social context in which a project will be deployed. Similarly, understanding the history of land use and environmental sensitivities is critical. Data may be gathered from economic databases, personal references, and regulatory databases and will play an important role in understanding project risks and benefits. The emissions associated with coal mines, for example, have been well studied and are summarized in the literature (Bhanu et al. 2018). Sector emissions can increase as resources that are more challenging to mine are exploited (Kholod et al. 2020), and CH_4 emissions from coal mines can persist. Ensuring that projects taking place have minimal or reduced impacts on communities is essential for project success. Life cycle assessments evaluating the environmental, public heath, and safety aspects of CCUS projects and pipelines are valuable resources for understanding potential social considerations (van der Giesen et al. 2017). Assessments are available that describe potential impacts of DAC systems (Deutz and Bardow 2021), of pipeline construction and operation (Strogen et al. 2016), and of risk and potential impacts of geologic storage projects (Khoo and Tan 2006). Little is understood about the impacts of EW projects, making them an important area for future research (Moosdorf et al. 2014) and for establishing best practices for safety and sequestration permanence.

Corporate investments in CCUS may drive development of projects, with capture projects getting registered for carbon trading every year in markets such as Frontier and Puro Earth, or directly by companies such as Microsoft, Shopify, and Stripe.

3.6 NUCLEAR POWER

3.6.1 Key Site Characteristics and Considerations

Aside from general considerations for siting nuclear power, the following considerations are specific to mine land.

Siting analysis

Table 3-7 lists siting criteria that may be considered for repurposing mine land for RPPs, including SMRs and other ARs that require fixed locations. Microreactors are not considered because they are often portable. Given strict regulations from NRC, population, geologic considerations, water considerations, land type exclusion, and vicinity to hazardous facilities and operations (i.e., facilities and their operations that may impact the operation of NPPs or vice versa) are well-understood criteria in NPP siting analysis and are supported by OR-SAGE. Different from CPP to RPP siting, siting analysis on current and former mine land has specific considerations for water, soil, and seismic conditions.

Table 3-7. Siting criteria for nuclear power generation tailored for mine land repurposing

Criteria	Category	Data sources
Population density	Population	ORNL (LandScan); US Census Bureau
Slope	Geology	National geospatial-intelligence agency; USGS
Safe shutdown earthquake	Geology	USGS; state geological survey
Subsoil condition to carry plant loads*	Geology	USGS; state geological survey
Landslide hazards	Geology	USGS
Stream flow	Water	USGS; EPA
Water storage capacity and quality (e.g., underground runoff)*	Water	State geological survey
Wetlands/open water	Land cover	USGS; US Department of Interior
Protected lands (a composite of 13 data layers)	Land cover	US Department of Agriculture National Forest Service; BLM; US Fish and Wildlife Service; National Wild & Scenic Rivers; National Atlas of the USA; and commercial sources
100 year floodplain	Vicinity to hazardous facilities and operations	Federal Emergency Management Agency
Ground water and surface water interaction*	Vicinity to hazardous facilities and operations	State geological survey
Proximity to hazardous facilities (a composite of airports, military bases, and petroleum refineries)	Vicinity to hazardous facilities and operations	Federal Aviation Admin; Bureau of Transportation Statistics; US Census Bureau
Proximity to fault lines	Geology	USGS

* Criteria that are specific to mine land

Population. NRC 10 CFR 100 regulation specifies population density requirements based on potential radiation dose. NRC RG 4.7 recommends population density of less than 500 persons/mi^2 for LWRs and at least 20 mi radial distance. OR-SAGE computes population density rings at 1 mi interval. With SMRs and ARs, OR-SAGE considers factors such as reduced core damage frequency, elimination of large-break loss-of-coolant accident sequences, smaller source term, reduced early release fraction, reactor vessels and containment vessels, and reactor building location for the inclusion of cells with population density above 500 persons/mi^2. Because many mine land sites are in remote areas, meeting the population criterion is more promising. OR-SAGE can conduct detailed analysis in this regard.

Geologic considerations. In OR-SAGE, seismic restrictions, proximity to fault lines, steep slopes, and landslide risk are geologic considerations for excluding candidate cells. A threshold for the safe shutdown earthquake peak ground acceleration (2% chance in a 50 year return period) can be set to exclude mine land sites. For LWRs, OR-SAGE sets the threshold to be 0.2. For SMRs and ARs, it is relaxed to 0.5. For fault line proximity, NRC 10 CFR 100 specifies a lookup relationship between fault line length and the standoff distance from an NPP site, which OR-SAGE uses as a geologic criterion. Slopes steeper than 12% for LWRs and 18% for SMRs/ARs are excluded. On land slide risk, OR-SAGE uses USGS landslide data to exclude moderate- to high-risk areas. For mine land, underground structures that evolve with mining are to be considered in addition to public geology data sources. Since mining may change seismic conditions dynamically, further assessment on local geological data is needed as a siting criterion. CPPs are often larger and heavier than NPPs, so subsoil condition may have been met. Siting on mine land, however, needs to consider subsoil condition to ensure that it can carry NPP loads. Sites with unstable or weak underground are to be excluded. Local geologic and seismic data are not public data. Data acquisition and partnership may be needed to access the data.

Water considerations. In determining exclusion criteria, wetland and open water cells, as well as cells fallen into the FEMA 100 year flood zone, are excluded. In addition, extreme weather events such as extreme wind speed, hurricane, and extreme snow or rainfall may be considered using frequency analysis, especially as extreme climate patterns become more frequent. Current and former mine land sites commonly have abundant high-quality water storage in abandoned sinks, which is a good source of cooling water for water-cooled reactors. However, if underground water is connected to surface water, the impact of contamination and water supply to surface river network must be evaluated.

Mine reclamation support. BLM supervises reclamation projects on current and former mine land. In those projects (BLM 2022), facilities such as wastewater treatment plants are built to restore and clean up abandoned mines for health and physical safety, environmental conservation, and economic growth. This is particularly important for hard rock mines with siting RPPs on mine land to provide sufficient power to reclamation infrastructure (e.g., water treatment plant, sulfate-reducing bioreactor) for processing deposition of dangerous substances from precipitation runoff from mines. Therefore, proximity to reclamation facilities may be considered in siting analysis.

Simulation of nuclear power plant deployment for future energy demand

In addition to siting analysis for identifying individual sites for NPPs, OR-SAGE can simulate the entire nuclear fuel cycle coupled with energy demand profiles to provide optimal siting in response to both exclusion siting criteria and projected energy demand. Users can modify simulation parameters to specify aggregated cells as nuclear-friendly zones that reflect community areas that may benefit collectively from policy incentives and other repurposing strategies. This capability may be particularly useful for mine land because mine land sites are often spatially clustered. Users can also specify the capacity of individual reactors and existing NPPs, and how adding reactors to existing or simulated NPPs and constructing new NPPs are prioritized. Based on user input and projected energy demand, the simulator produces a trajectory of building nuclear power to meet regional energy demand over time. By tuning input parameters, the simulator can produce different NPP deployment profiles to reflect changes from policy and provide scenario analysis capabilities for decision makers.

3.6.2 Infrastructure Access

The analysis of reusing existing infrastructure at mine land is based on the four identified types of components that may be present at current and former mine land in the 2020 EPA RE-Powering report: electricity transmission and distribution system equipment, physical security (protective electric equipment), dormant power generation, roads, and civil and structural facilities. In addition, current and former mine land sites often need reclamation efforts to restore and clean up abandoned mines. Infrastructure may be shared between reclamation and NPPs, such as boundary fences.

Mine power systems

Mine power system receives electricity from utility companies and transforms it to operation voltage to drive mining equipment (e.g., motors). In a mine power system (Morley 1990), the substation, switch house, and power center are three major components. Substations receive power from utility power company. Switch houses are disconnecting (i.e., to disconnect power manually) and sectionalizing equipment (i.e., to provide protective relaying and branching of the radial system). A principal component of a switch house is an automatic circuit breaker. Power centers, also called load centers, convert distribution voltage to utilization voltage. They are located to facilitate underground mining. It is worth noting that portable substations, switch houses, and power centers are popular and, thus, less useful for reuse. Substations are usually built on concrete pad with good grounding and may be considered for reuse. Distribution equipment in a mine power system, including powerlines, cables, cable couplers, trolley lines, may be refurbished, but has less significance in repowering for NPPs. Mine power system components may have limited reutilization value for NPPs, but some components may be reused on small reactors such as portable microreactors. Mine land sites have extensive protective equipment to protect against hazardous situations such as lightning. They often have well-built ground bed, which is underground conductor complex to provide low resistance connection to infinite earth. Ground bed may be ungrounded neutral, solidly grounded neutral, low-resistance grounded neutral, or high-resistance grounded neutral. The grounding infrastructure may be (or may not be) considered for reuse as a type of physical security equipment. Other reusable protective equipment includes switches, circuit breakers, fuses, and relays.

SMR generators have a high spinning inertia compared with PV arrays and wind farms that respond with small and medium inertia at electrical fault situations, respectively. Four main types of SMRs are being pursued: LWRs, fast neutron reactors, graphite-moderated high-temperature reactors, and various kinds of molten salt reactors. LWRs have the lowest technological risk, but the fast neutron reactors can be smaller, be simpler, and have longer operation before refueling. Some molten salt reactors are fast spectrum (i.e., fast reactor) and produce a fission chain reaction that is sustained by fast neutrons, carrying energies of 1 MeV or greater (World Nuclear Association 2023).

The installation of a small nuclear reactor generator plant requires a small to medium electrical substation, so protective relays for differential protection, feeder protection, generator protection, and transformer protection applications are needed (Schweitzer Engineering Solutions 2023c). Protective relays could be electromechanical, static solid-state, or numerical processor types. The use of numerical processor protective relays is a high priority in nuclear reactor plants (and SMRs) because they provide multiple protection functions, self-monitoring/-testing, high accuracy, less calibration, fast speed, sensitivity, resistance to seismic forces, susceptibility to electrical transients, multiple setting groups and programmable logic built in, and recording and reporting capabilities with communication (Henmark 2017). The general technical requirements necessary for electrical equipment intended for use in Swedish nuclear power stations are specified in TBE 100. It defines that microprocessor devices (e.g., protective relays, other devices) must be avoided in environments where they may be exposed to an integrated ionizing radiation exceeding 10 Grays during their lifetime.

Civil and structural facilities

For water-cooled RPPs, abundant water stored in abandoned pits is an advantage of mine land. If the existing water storage, supply connection, and drainage system can be reused for cooling purposes, the cost of RPP construction may be reduced. An underground power system may also be reused to pump water from sink to surface.

Unlike CPPs, mine land does not have enough buildings ready for RPPs. However, for abandoned mines, reclamation projects may set up protective fence and other infrastructure that may be shared with NPP sites.

Transportation

Mined coals and minerals are transported to ports and plants via roads and rail, even if a mine land is in a remote area. Similar to CPPs, RPPs can reuse their transportation infrastructure, if still available and functional.

3.6.3 Regulatory Considerations

Mine land may be in remote, isolated areas, which may offer an advantage in obtaining permits for RPPs because of the reduced risk of failure impact.

3.6.4 Economic and Resource Considerations

Building RPPs in remote areas with few people and scarce power supply may provide economic development opportunities to local communities because of the resulting infrastructure upgrade. If mine land sites are close to CPPs, repowering CPPs and repurposing mine land may be considered together to optimize resource allocation and maximize social and economic impact.

3.6.5 Social Considerations

For nuclear power, social acceptance is crucial, and issuing a "social license" to a nuclear facility has been difficult for all affected units of government and community (Lovering et al. 2021). Regarding NPP siting, a just and equitable process must be developed across the energy sector by including other disciplines, particularly social, behavioral, and decision sciences (Lovering et al. 2021). This procedural justice approach is a crucial path for successful public participation and building trust in a committed way (Frances Johnson et al. 2022). Specifically, procedural justice can help determine community's baseline knowledge, assess risks from how they are perceived by the public, and develop a social contract based on designing a new energy system. Case studies in other industries such as nuclear decommissioning, aviation, wind, solar, and pipeline provide additional lessons and experience. For new reactor designs such as SMRs, successful demonstrations with safe operation records in other locations may increase social acceptance (Frances Johnson et al. 2022).

3.6.6 Knowledge Gaps

For NPP siting on mine land, the following knowledge gaps have been identified:

- There is no real-world example for repurposing mine land with nuclear power, to the best of the authors' knowledge. Therefore, many unknowns may only be answered through actual demonstration projects.

- The siting methodology discussed in this section was adopted from the practice and literature of repowering CPPs. Additional studies will be needed to solidify the details of the methodology for mine land applications.

- Although there is a general understanding of social acceptability on nuclear power, it is still unclear how specific communities in mine land areas would respond to nuclear as a new energy option, including ARs.

- Further understanding of the differences in mine land types (e.g., surface vs. underground) and the variety of mine land status (e.g., abandoned, sealed, active mine land) is needed to assess how such differences factor into a siting analysis.

- For off-grid applications such as microgrids, microreactor technologies may be considered. However, the research and demonstration of microreactors are still at an early stage.

- A reliable market supply of high-assay low-enriched uranium, which would be required for the operation of many ARs, is the highest supply chain priority for the deployment of advanced nuclear energy in the United States.

3.7 HYBRID PROJECTS

Hybrid projects may provide more opportunities for the deployment of clean energy technologies on mine land. For instance, solar can be combined with energy storage and the two can provide the energy necessary to power CO_2 capture and sequestration in the subsurface. Geothermal may also power CO_2 capture. Subsurface thermal energy storage may compete for subsurface assets with CAES. Nuclear energy can coexist with all technologies and may benefit from backup energy storage options. Energy storage can improve the capacity factor of renewable energy system and provide steady power for CO_2 capture. Carbon dioxide capture systems are likely to require pipelines and sequestration systems. A few possible combinations of the considered technologies are discussed below.

3.7.1 Compressed Air Energy Storage and Thermal Storage

One option for a hybrid project consists in coupling an energy generation technology with an energy storage technology (e.g., CAES) if a local need exists to store waste energy to use at a different time. In this section, CAES is presented as an example of a hybrid system. Conventional and existing CAES plants are diabatic, meaning that the heat generated during the compression process is released and wasted. NG is added during the energy recovery phase to overcome severe decompression cooling that would otherwise occur in the turbine. In an A-CAES system such as those proposed for future CAES plants, the heat generated during air compression is stored and later used to warm the decompressing air in the electricity-generating turbines. This eliminates the need to combust NG, which can increase the system efficiency and avoid CO_2 emissions from NG combustion. One promising option is to couple A-CAES with a thermal local rock-based energy storage system. For example, Barteka et al. (2022) demonstrated how a mine shaft can be converted into a hybrid reservoir for CAES and thermal energy storage, as illustrated in Figure 3-17. Based on their design and analysis, they concluded that (1) making use of existing mine infrastructure for a hybrid energy storage system reduces system cost and energy losses from transmission; (2) a system using a shaft with 60,000 m^3 volume can have an energy capacity of 140 MWh; and (3) the round-trip efficiency (the portion of the energy recovered compared with the total energy stored) of such a system is 70.44% with a two-stage compressor and turbine. The maximum temperature of the compressed air did not exceed 310°C.

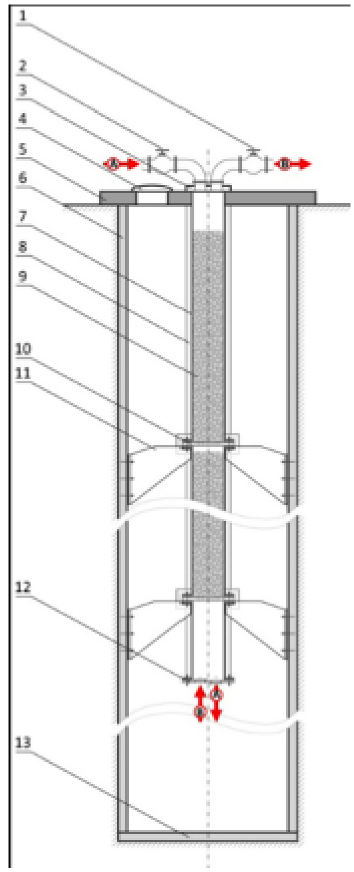


Figure 3-17. Concept of a hybrid reservoir for compressed air and heat. (1) Shut-off valve on the outlet pipeline, (2) shut-off valve on the inlet pipeline, (3) thermal energy storage unit cover, (4) revision hatch, (5) compressed air reservoir cover, (6) cylindrical underground tank casing (e.g., mine shaft), (7) cylindrical element of the thermal energy storage system, (8) thermal insulation of the thermal energy storage system, (9) heat accumulation material, (10) perforated bottom, (11) vertical positioning of the thermal energy storage system, (12) bottom of thermal storage unit with pressure flaps, (13) bottom of cylindrical underground tank. Credit: Barteka et al. (2022).

3.7.2 Compressed Air Energy Storage and Pumped Storage Hydropower

A second potential hybrid option is between CAES and PSH. Deng et al. (2019) provided a design for such a hybrid system in coal mine railway tunnels. They proposed a combination of PSH and CAES methods, and use of flexible bags to store compressed air for a typical configuration of a CAES system, as shown in Figure 3-18. They conducted an analysis to understand the power generating capacity and optimal operation time for roadways at different depths. A combination of CAES and PSH can help maintain a relatively constant air pressure during the CAES system electric power generation period. Inexpensive flexible rubber bags are used to store compressed air in the roadways, which separates air from water and eliminates the possibility of air leakage into the surrounding bedrock. Because the air pressure is determined by the pressure head of the reservoir, railroad tunnels at shallow depths may not provide enough air pressure. Larger storage volume can be used to make up the capacity requirement for shallow roadways. By using the existing infrastructure at a mine site, the cost of building such a CAES and PSH system would be greatly reduced.

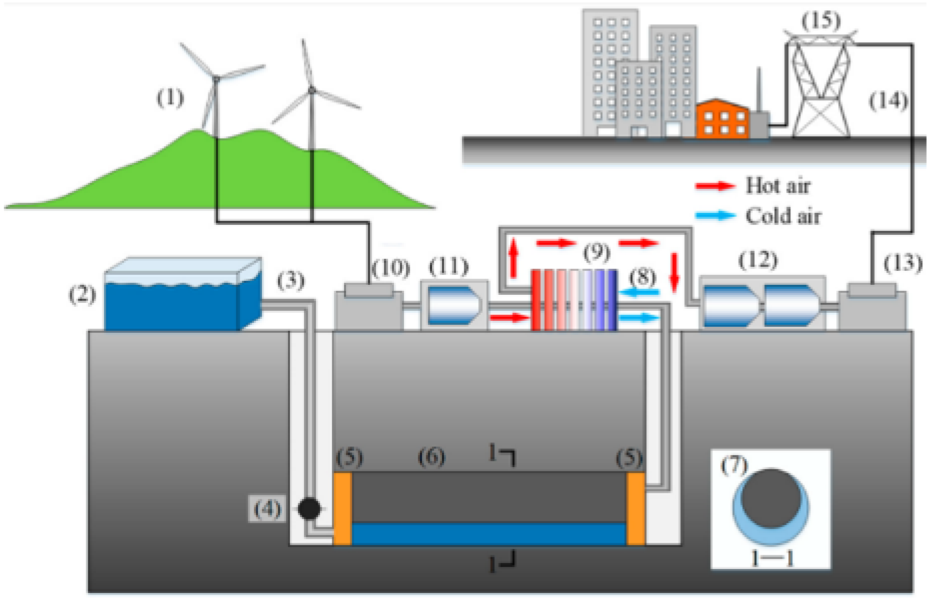


Figure 3-18. Design of a CAES and PSH hybrid system. The system includes (1) a form of renewable energy source (wind or solar), (2) reservoir, (3) water pipe, (4) water pump, (5) plugging wall, (6) roadway, (7) flexible bags, (8) compressed air pipe, (9) heat storage unit, (10) electromotor, (11) compressor, (12) turbines, (13) generator, (14) power lines, and (15) power grid. Credit: Deng et al. (2019).

3.7.3 Compressed Air Energy Storage and Geothermal Technology

The use of NG for energy recovery in a conventional diabatic CAES system could be replaced by a hybrid system. An example of such a hybrid configuration including geothermal power generation and A-CAES was proposed for the Yakima Minerals Plant (McGrail et al. 2013). During the air compression stage, geothermal power can be used to cool the centrifugal compressor, and heat from compression can be captured and stored in molten salt. During the decompression stage, geothermal power and heat recovered from the molten salt can be used to preheat the pressurized air. Furthermore, molten salt storage increases the efficiency of the system. The hybrid plant was designed to run at 150 MW of load during storage and provide 83 MW of generation capacity.

4. METHODOLOGIES FOR ESTIMATING TECHNICAL POTENTIAL

In this section, detailed methodologies are presented to estimate the technical potential of various clean energies.

4.1 SOLAR POWER

Orthogonal area modeling

There is a substantial body of research dedicated to orthogonal area modeling. In this type of models, the terrain for mounting PV systems is considered flat, without any elevation changes. The models mentioned in the literature review operate under the assumption of the flat terrain.

The general principle modeled in orthogonal methodology can be summarized as follows.

$$P = I_{ref}\left(C_0 E_e + C_1 E_e^2\right)\left(1 + \alpha\left(T_c - T_{ref}\right)\right) * \left(V_{ref} + C_2 N\delta \ln E_e + C_3 N(\delta \ln E_e)^2 + \beta\left(T_c - T_{ref}\right)\right) \tag{4-1}$$

where

- P is the power at maximum power point (W);
- N is the number of cells in the array;
- I_{ref} is the reference current at a nominal temperature and effective irradiance coefficient E_e of 1 (A), ranging from 0.27 to 21.44 depending on the hardware;
- V_{ref} is the reference voltage at a nominal temperature and effective irradiance coefficient E_e of 1 (V), ranging from 7.5 to 86.6752 depending on the hardware;
- E_e is the effective irradiance coefficient calculated from air mass, angle of incidence, diffuse horizontal insolation, global horizontal insolation, and direct normal insolation (W/m^2);
- T_c is the actual cell temperature (°C) and T_{ref} is the reference temperature, 25°C;
- C_0, C_1 are empirical coefficients relating current at maximum power to effective irradiance coefficient E_e; C_0 is set to −0.000002, and C_1 is set to −0.000047;
- C_2, C_3 are empirical coefficients relating voltage at maximum power to effective irradiance coefficient E_e; C_2 is set to −0.001861, and C_3 is set to 0.000721;
- α is the temperature coefficient for short circuit current, normalized to be applicable for individual panels and multiple panel systems, ranging from 0 to 0.00147 depending on the hardware;
- β is the temperature coefficient for module open-circuit voltage, usually set to a constant ranging from −0.0232 to −0.423 depending on the hardware; and
- δ is the voltage coefficient at given cell temperature, set to 26 mV per cell at 25°C.

Existing models take irradiance inputs, usually diffuse horizontal insolation, global horizontal insolation, and direct normal insolation, and build a unified irradiance value that describes how much sunlight reaches the surface of a PV module (as the sum of direct normal times cosine of incident angle, plus diffuse times view of the sky, plus ground reflected times view of the ground). This irradiance is then related to the module output through a set of empirical coefficients. The results are adjusted for temperature to account for a decline in PV module performance in warmer-than-nominal ambient temperature. Total hourly output is influenced by the selection of the hardware, and models usually offer a variety of PV module and inverter options.

The model inputs including irradiance, air temperature, and wind speed are provided at NREL's NSRDB[31] or NOAA's ASOS and AWOS data sets.[32] However, NSRDB was found to have some unsystemic data issues related to air temperature. Therefore, it is recommended to use NOAA temperature data.

The existing orthogonal models include a variety of realistic assumptions about the operation of PV. For more detail on the empirical coefficients including air mass, temperature, beam component, please see the report by Kratochvil et al. (2014). Additional effects such as soiling, shading, irradiance, tracking, or hardware characteristics, can be found at the System Advisor Model.[33] Models are usually capable of using data on different weather conditions, including overcast or partial cloud cover. The only significant limitation that pertains to the use of orthogonal model for coal mines is the assumption of flat terrain. Coal mines represent a change in terrain and may be located in areas of uneven elevation, which implies two immediate details. First, the sky view for coal mines would necessarily have a variety of missing sections due to surrounding landscape. Second, the elevation change requires a much higher data resolution, which could account for changes in the sky view within respective segments of NSRDB grid. The regular orthogonal models may, as a result, be unable to fully capture the effect of terrain.

Elevation adjusted modeling

The terrain limitation of orthogonal models is addressed in a number of solutions that deal with elevation adjusted PV output. These include GIS based models such as PVWatts[34] and Visual Solar.[35] The inputs including elevation can be found in IMBY[36] data and USGS.[37] While the primary use of these models is usually rooftop solar, they can be adopted for the estimation of PV output in any conditions of partial shading and elevation, including coal mines.

The importance of elevation adjusted modeling is demonstrated in Figure 4-1. Figure 4-1a contains the satellite image of Bozeman, a former mine site at (45.10, −110.80) in Park County, Missouri. Figure 4-1b shows the terrain from the USGS maps.[38] Figure 4-1c shows the solar irradiance adjusted for June 21 and December 21.

The figure demonstrates that south-west facing areas of the mountain receive a lot more sunlight than the northern slope. Placing the PV modules on the shaded area of the mountain would not yield substantial result even if the modules had optimal alignment and angle to the horizon.

31 https://nsrdb.nrel.gov/
32 https://www.noaa.gov/
33 https://sam.nrel.gov/photovoltaic/pv-publications.html
34 https://pvwatts.nrel.gov/
35 https://www.osti.gov/biblio/1232367
36 https://maps.nrel.gov/
37 https://www.usgs.gov/products/data
38 https://apps.nationalmap.gov/downloader/#/

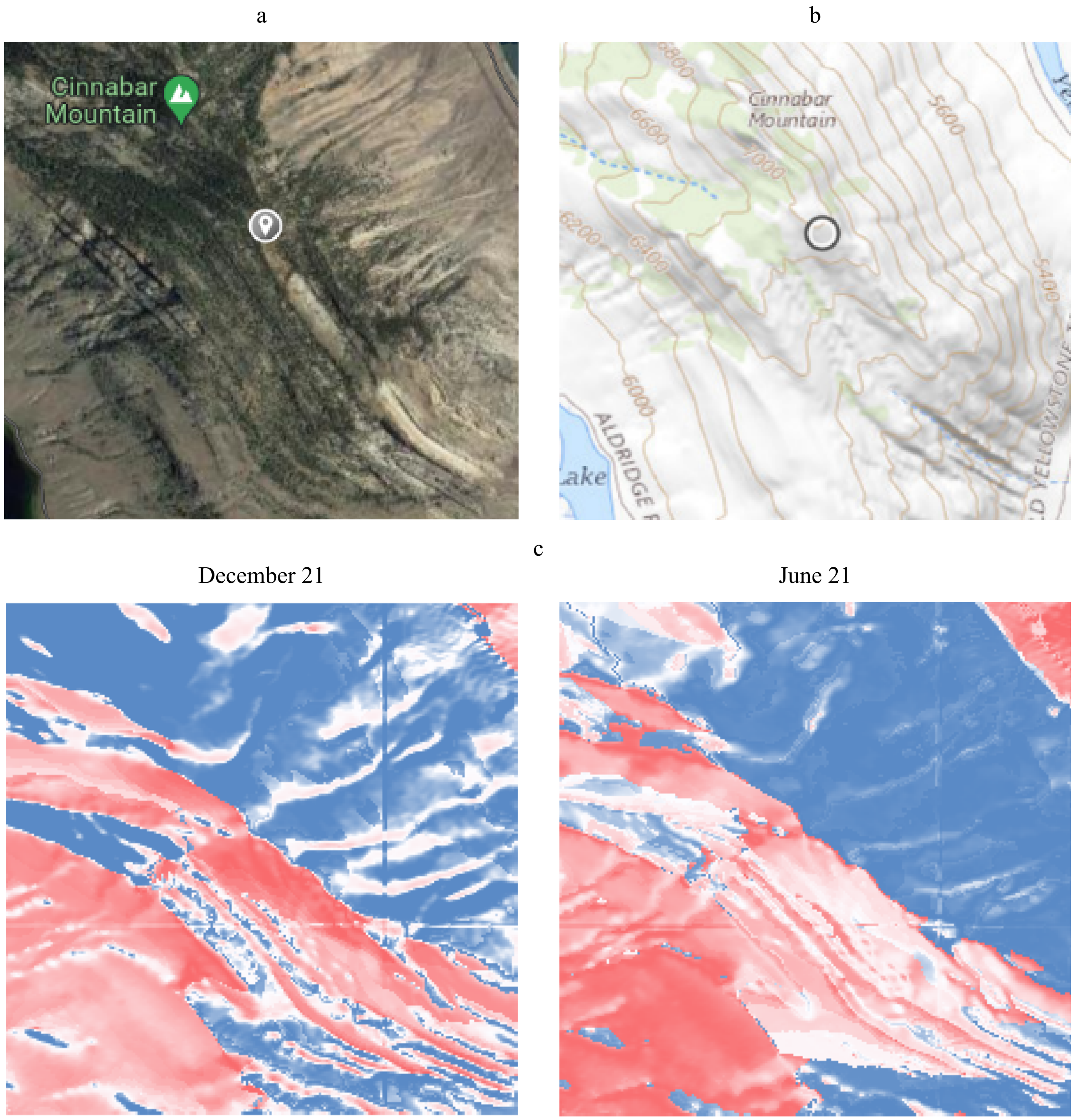


Figure 4-1. Terrain and solar irradiance for a former mine land in Park County.

Technical potential

To illustrate the technical potential of a PV on current and former mine land, consider the Decker coal mine in Big Horn County, Montana, (44.77, −111.14), along with a PVWatts calculator. Decker Mine is a bituminous coal surface mine that is still operating and has the capacity to place a 100 MW PV site on part of its area. The location of the mine and the illustrative PV system as a part of the mine is shown in Figure 4-2.

Figure 4-2. Decker Mine, Big Horn County, Montana.

The technical potential of the system would depend on the configuration of the system and the weather conditions along with the geographical factors such as irradiance, angle, and azimuth. The system reviewed in this example has a standard in built configuration: fixed rack, Crystalline Silicon modules with 19% efficiency and anti-reflective coating glass cover. The tilt used for the calculation is 30 degrees. This represents a deviation from the original 20 degrees in the calculator due to the latitude of the location. The azimuth is 180 degrees. The system losses are set at 14.08%, the DC to AC size ratio is set at 1.2, the inverter efficiency is set at 96%. PVWatts uses NSRDB irradiance data, with the model values corresponding to the typical weather in the area rather than the actual historical data.

The hourly AC output from the illustrative 100 MW PV array is provided in Figure 4-3. On a full sun day, the output can reach 80–90 MWh, and on days with less sun it can be as low as 10 MWh.

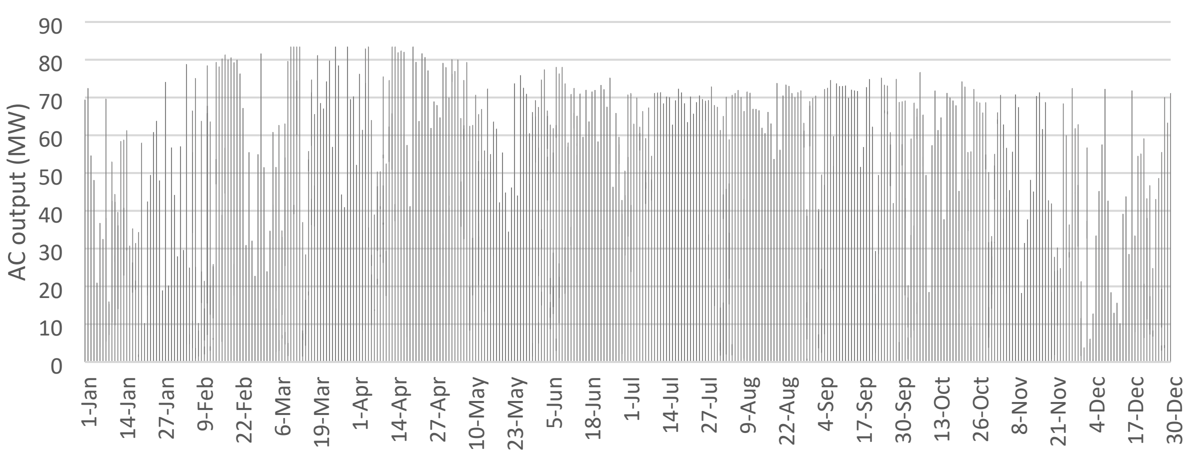


Figure 4-3. Hourly PV output of the array.

A more focused analysis of hourly values shows that the average output for a 100 MW PV system is about 50 MW during the peak production at noon, and ranges between 20 MW and 40 MW during morning and evening hours. The production during early morning and evening peak of 7–8 p.m. is negligible (Figure 4-4).

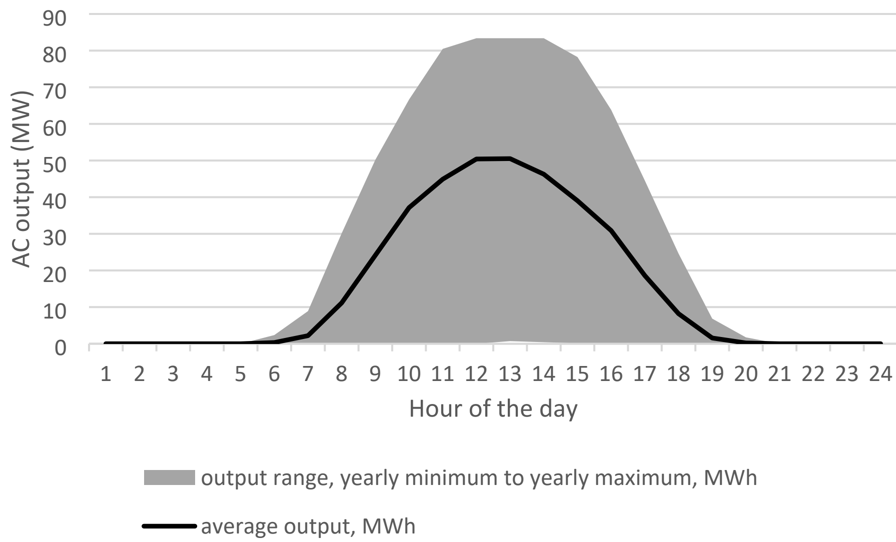


Figure 4-4. Minimum, maximum, and average hourly output.

The total AC output of the system is estimated at 133.4 GWh per year, and the capacity factor is about 15%. This information can be further used to provide a basic illustration of the commercial potential for the system.

Commercial potential

Sections 2 and 3 discuss that revenue for a PV project could be acquired from fixed contracts or the wholesale power market for independent power producers or from local utility rates for vertically integrated utilities. This example uses wholesale power prices to illustrate the commercial potential of the 100 MW PV system discussed in the previous section.

The illustration of the revenue generation a PV system is provided in Figure 4-5. The output discussed in the Technical potential section does not generate a constant average revenue throughout the day. The right axis shows the MISO wholesale power prices in the hub of Minnesota, the closest geographical pricing area to the illustration system. The price is taken for December 5, 2022, but any type of prices such as yearly average of TDY prices can be used for the analysis.

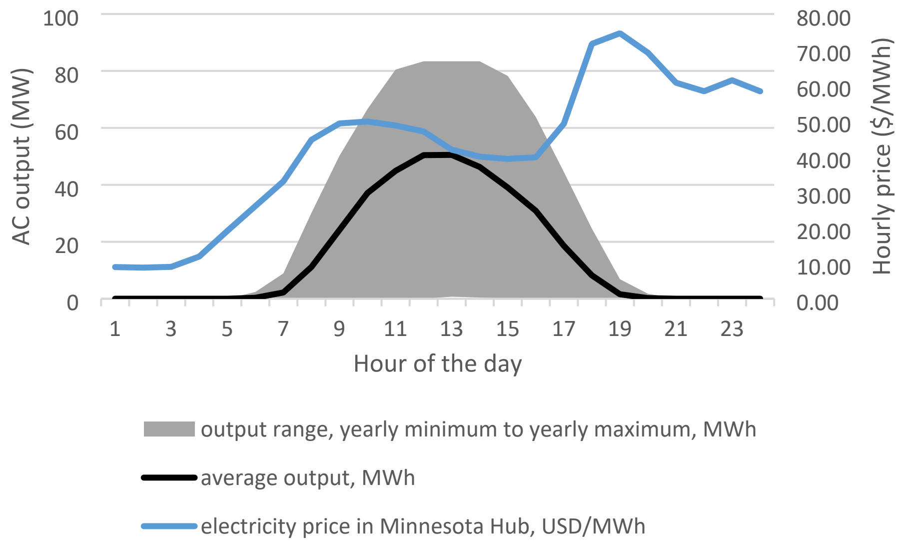


Figure 4-5. Minimum, maximum, and average hourly output and the wholesale electricity price.

Electricity prices tend to be higher during morning and evening hours, when the PV output is low. As a result, the PV system on average receives a lower average price for its volume than the rest of the market.

The illustration system described in the previous section would receive an average of $6 million for 1 year of operation given the prices provided in this example. The average revenue per day is illustrated in Figure 4-6.

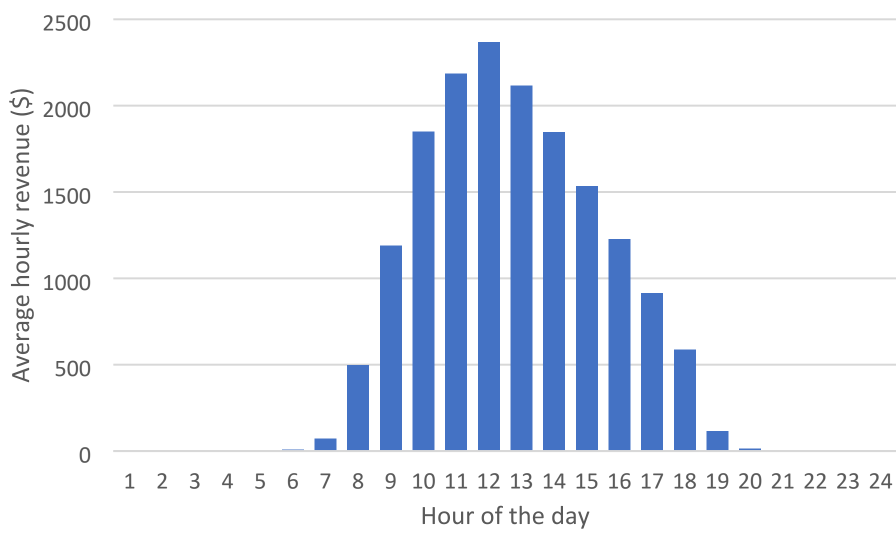


Figure 4-6. Average revenue per hour of the day.

The average daily revenue and the total revenue per year allow to calculate the financial characteristics of the illustrated PV example.

The basic financial metrics used for project evaluations are NPV, adjusted internal rate of return, and LCOE (¢/kWh). The NPV of the project equals a sum of operating cash flows discounted by r, the average rate of return that the market expects from PV projects. NPV is calculated according to the following formula.

$$NPV = -Inv + \sum_t \frac{CF_{operating,\,t}}{(1+r)^t} \tag{4-2}$$

The initial investment cash flows can be discounted if the project takes several years to build, in which case the formula can take the following structure. The $CF_{in,\,t}$ includes the revenue from selling electricity to the market, while $CF_{out,\,t}$ includes the investment costs and operating expenditures such as labor and materials.

$$NPV = \sum_t \frac{CF_{in,\,t} - CF_{out,\,t}}{(1+r)^t} \tag{4-3}$$

More sophisticated ways of evaluating the financial viability of a PV project, including the commercial and public tools, were discussed in Section 2. Here, the basic NPV calculation includes the following inputs. The initial cost of developing a project is assumed at 80 million (Hyder 2022). The number of people required to operate a 100 MW PV system is three (SRP 2020), which brings the annual labor cost to about \$240,000. The rate of return established during the expert interviews was about 5%, which increased since June 2022 to an estimated 8%. The assumption of growing electricity prices and wages is also included in this example with the growth rate of 5% per year. For a 30 year duration of the project, this would yield the following calculations and a NPV of over \$40 million.

$$NPV = -80 + \sum_{t\in[0,\,30]} \frac{(6-0.24)*1.05^t}{(1+0.08)^t} = 40.7 \tag{4-4}$$

Although these numbers do not represent any actual performance of a project, they represent the mechanism of transforming PV output into cash flows and using the cash flow to estimate the commercial potential of a project.

The breakeven point of the project is the year in which the sum of net discounted cash flows exceeds the original cost of investment, which is year 17 in this example.

4.2 CARBON CAPTURE AND SEQUESTRATION

4.2.1 DIRECT AIR CAPTURE

The National Academies set an estimate on the technical potential of DAC and provides an overview of the state of technology (key parameters provided in Table 4-1). The theoretical minimum energy to separate 75% of CO_2 at 400 ppmv in air at 25°C in a 98% purity stream is 0.45 GJ/tCO_2. In comparison, a solvent-based system that requires high temperatures for regeneration has closer to 8.2–11 GJ/t in real work and the solid sorbent system has 1.9–23.1 GJ/t in real work (this large range reflects the uncertainty around desorption processes). The committee proposed assumptions for energetics, carbon footprint and cost in their comparison of DAC systems. Special attention is paid to the source of heat and electricity, as any emissions associated with the capture process must be subtracted from the capture amount to derive an efficiency (Deutz and Bardow 2021). In the case of the solvent system, the exhaust gas from the NG heating system can be fed into the DAC system for additional CO_2 capture.

Table 4-1. Key parameters and base case values used by the National Academy of Science to compare across DAC technologies and related energy sources. Geothermal energy was not included in the study but would be relevant for some project on mine land

Parameter	Value
Plant capture rate from air	1 MT/year
Concentration in air	400 ppmv CO_2
Volumetric flow rate	58,000 m^3/s air
Capture fraction from air	60% CO_2
Concentration of product	98% CO_2
Plant life	10 years
Emission factors	
Heat from NG	227 gCO_2/kWh
Heat from coal	334 gCO_2/kWh
Heat from nuclear	4 gCO_2/kWh
Heat from solar	8.3 gCO_2/kWh
Electricity from average grid	743 gCO_2/kWh
Electricity from NG	450 gCO_2/kWh
Electricity from coal	950 gCO_2/kWh
Electricity from nuclear	12 gCO_2/kWh
Electricity from solar	25 gCO_2/kWh
Electricity from wind	11 gCO_2/kWh

Engineering cost breakdowns are publicly available for several leading technologies and companies, including Carbon Engineering (Keith et al. 2018) and Climeworks, and were critically reviewed by a National Academy of Science committee. In general, DAC systems include an air contactor, regeneration system, and CO_2 compression system. The sizing of the system depends on the design of the contactor, which determines the necessary contact area, packing material, and air speed. Energy will come from the fan and overcoming pressure drops in the contactor, the solvent pump, and the provision of thermal energy for regeneration. Costs will also come from chemical or packing material makeup, which is a key uncertainty and varies among companies. Generally, the solvent-based approach requires $CaCO_3$ and KOH, whereas the sorbent-based approach requires new sorbent. Maintenance of the system will include cleaning the system of foreign contaminants and replacing components.

Data needs

- Energy availability: electricity, thermal
- Energy reliability: need for energy storage, backup power
- CO_2 storage transport utilization sequestration infrastructure
- Land availability
- Water availability
- Steam availability
- Ability to truck chemicals / materials to location
- Integration of DAC system with other clean energy technologies and existing infrastructure

4.2.2 ENHANCED WEATHERING

Analysis of EW projects should include a preliminary technoeconomic analysis and life cycle assessment. Example costs for EW were recently reported for primary equipment and energy (Bullock et al. 2021). Rock pretreatment and field application dominated costs, with minimal costs associated with the 300 km of transportation assumed. The main GHG emission fluxes associated with EW include the following:

- Any processing of the mining waste or tailings, such as comminution; aeration, stirring, and spreading; and transport
- The possible CDR potential, which will depend on material type and operation conditions
- End of life of the material, including transport and disposal

Estimating CDR potential requires chemical composition and particle size distribution data on the rock waste and mine tailings. If these data are not available, prototypical values for representative mine wastes can be used to approximate potential (Bullock et al. 2021). Particle size will affect weathering rates and is important for estimating pretreatment equipment and energy. Rocks that have been crushed will likely need to undergo further milling or grinding. The energy intensity of mechanical pretreatment is correlated with the ultimate target particle diameter. A typical metric is P80 ≤ 100 µm (Moosdorf et al. 2014), which is the particle size at which 80% of particles pass when screened and that achieve complete weathering within 1 year. Equipment for mixing or moving tailings is assumed to use diesel. Comminution equipment may use diesel or electricity.

The composition of the mine tailings can then be translated into CDR potential using an approach based on Steinour (1959) (Bullock et al. 2021). This approach does not account for reaction rates and simply estimates alkalinity from soluble cations.

$$Epot = \mathrm{M\ CO_2} 100 \cdot (\alpha\mathrm{CaO\ M\ CaO} + \beta\mathrm{MgO\ M\ MgO} + \varepsilon\mathrm{Na_2O\ M\ Na_2O} + \theta\mathrm{K_2O\ M\ K_2O} + \rho\mathrm{MnO\ M\ MnO} + \gamma\mathrm{SO_3\ M\ SO_3} + \delta\mathrm{P_2O_5\ M\ P_2O_5}) \cdot 10^3 \cdot \eta\ , \tag{4-5}$$

where CaO, MgO, SO_3, P_2O_5, MnO, Na_2O, and K_2O are molecular mass concentrations of major element oxides and η is the molar ratio of CO_2 to cation sequestered during EW. For silicate minerals, $\eta = 2$, but a conservative value of 1.5 can be used to consider buffering in a seawater carbonate system (Bullock et al. 2021). The presence of phosphorus- and sulfur-bearing materials reduces CDR potential, and high Al and Fe can also reduce CDR because they form insoluble secondary materials during the weathering process. The presence of Mg-Fe-Ca increases CDR potential. Brucite is known to have a high CDR potential that has a fast dissolution rate. For reference, brucite has an ultrahigh CDR potential of more than 1,200 kg CO_2/MT of material, and mine wastes with a CDR potential below 400 are common.

Several international studies have evaluated mine tailings for the purpose of CDR or for use in cement, including ultramafic mine tailings from asbestos, silicate, chrysolite, Ni, raglan, and diamond production (Gou et al. 2019).

Data on mine tailing quantities are limited, but data on mines from USGS offer insights based on the asset mined and the types of host rock (USGS 2022). The US Department of the Interior estimates 45% of all mass handled in Fe mining is waste (USGS 2022). Most mine tailings are considered uneconomical and are left in storage facilities near or on the mine. More than likely, mine tailings will either be treated on site and remain at the existing disposal facility or transported by truck and tractor for land application. Tailings may still be hauled and spread on site to increase their exposure to ambient air, or to place them in constructed greenhouses. The truck fleet required to move mining waste to a field site depends on the bulk density of the material and the quantity moved in each time period. For a rock flour or powder material, bulk densities of 1,800 kg/m^3 can be assumed. The number and fuel consumption of diesel trucks can be easily estimated based on the truck weight, payload limit, road weight limit, distance, and driving speed. For example, diesel trucks with a payload of 14.5 MT and average fuel consumption of 6.5 mpg (60% greater fuel consumption when full (Sandhu et al. 2015)) can be assumed, although many large B-train trucks are also commercially available and can transport up to the US Department of Transportation limit of 70 MT. Tractors for land application also consume diesel, and fuel consumption depends on the soil type and necessary leveling; rock dust dispensing can be modeled similarly to dry bulk fertilizer dispensing. Application rates from 45 to 200 MT per acre have been reported but appear to be empirical.

Data needs

- Tailing generation per year (historical and projected)
- Tailing composition
- Existing tailing storage facility/disposal practices
    - Depth
    - Open/closed
    - Saturation
    - Disposal permits and requirements for on-site or off-site export of tailings
    - Risk of leachate and emissions to environment
- Land availability
- Heat and moisture available for greenhouse enhancement of mineralization

4.2.3 Carbon Capture, Utilization, and Sequestration

In this section, approaches for determining the technical and commercial potential of CCUS, DAC, and EW technologies are discussed. Each can be evaluated based on general life cycle phases (Figure 4-7), but material and energy balances and life cycle impacts will vary with location.

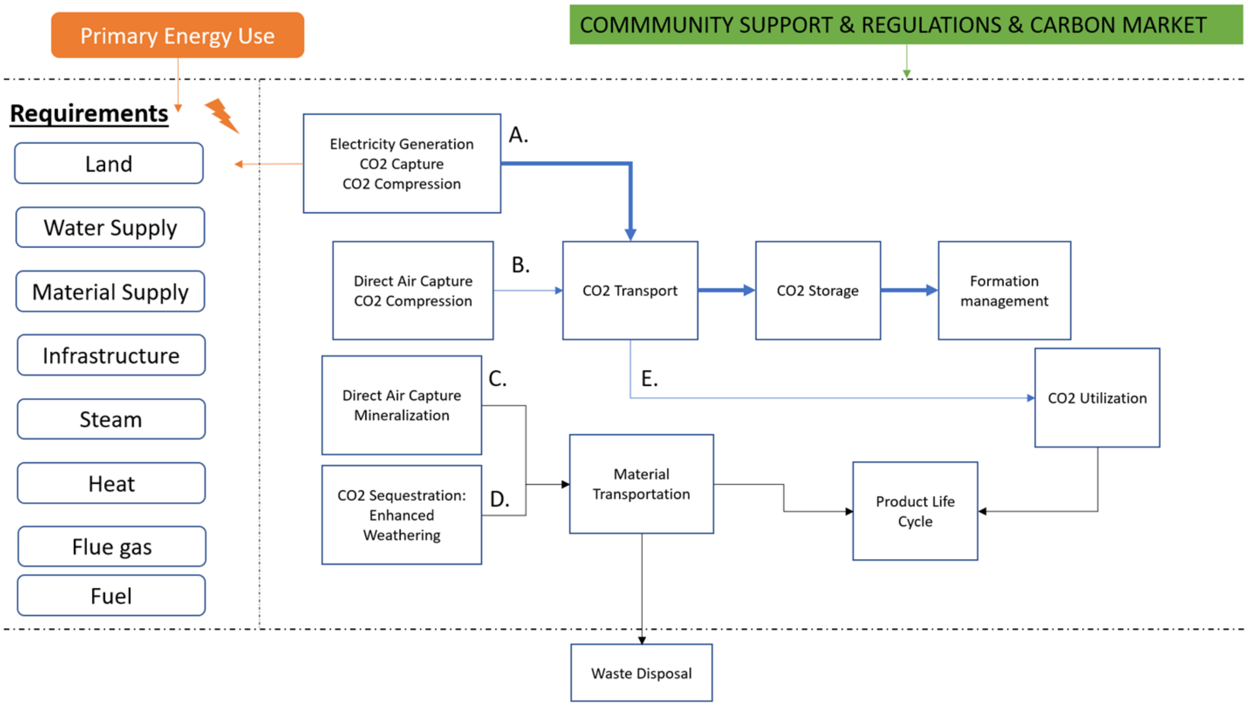


Figure 4-7. Technology system life cycle phases for CCUS and DAC. In pathway A, CO_2 is captured from a fossil fuel power plant and delivered to a geologic injection site for storage. Formation management may include brine processing, in which case products might be sold. In pathway B, CO_2 is captured directly from ambient air in a DAC system, compressed, and transported to a geologic injection site, or to a CO_2 utilization site in pathway E. In pathway C, CO_2 is mineralized, and materials are either sold as products or disposed of. In pathway D, mining waste and mine tailings are reacted with captured CO_2 or ambient air either on site or by way of terrestrial deposition (land application).

Numerous approaches have been published for predicting the technical and commercial potential of carbon capture at coal and NG power plants in the United States. The IPCC5 estimates that as much as 14% of GHG emissions reductions could come from carbon capture and sequestration (IPCC 2014). In 2011, the International Energy Agency (IEA) published a summary report on the cost and potential of CO_2 capture from power generation (Finkenrath 2011), focusing on large-scale (>300 MW net power) coal and NG power plants. For reference, a 500 MW coal-fired power plant could produce 10,000 MT CO_2/day (Herzog 1999). Capture technologies include amine-based post-combustion capture at NG and coal-fired power plants, pre-combustion at integrated gasification combined cycles, and oxy-combustion from pulverized CPPs. Many coal-fired power plants are collocated with coal mines, making them attractive targets for the Clean Energy Demonstration Program on Current and Former Mine Land initiative involving CCUS. The capture of CO_2 is also possible at other point sources near mines, but these are outside the scope of this analysis.

One approach for estimating technical potential of capture at power plants is as follows:

- Gather individual power plant data available through the US Energy Information Agency and the EPA eGRID database.[39]

[39] https://www.epa.gov/egrid

- Screen power plants based on age, size, and proximity to mine land with geologic sequestration potential.
  - To estimate technical and commercial potential of carbon capture at powerplants, Sathre and Masanet (2012) proposed modeling power plant fleet dynamics through 2100. In their model, carbon capture is deployed as early as 2020, which is consistent with forecasts made by IEA and the National Energy Technology Laboratory. Carbon capture is first installed on new power plants or during the retrofitting of existing power plants, with a preference for retrofitting newer power plants built after 2010.
- Estimate CO_2 capture potential assuming pre-, post-, or oxy-combustion based on the fuel type and an assumed capture efficiency.
  - Emissions that can be captured from power plants are based on the efficiency of the power plant, the type of coal and its carbon intensity, and the capture technology. IEA suggests a capacity factor of 85% for both coal and NG power plants, and an economic life of 30 years for NG and 40 years for CPPs. The relative decrease in net efficiency from capture varies with fuel type and power plant type but is generally 20%–29% for post-combustion capture, 14%–26% for pre-combustion capture, and 19%–27% for oxy-combustion capture.

Carbon dioxide utilization can occur via electrochemical pathways to produce fuels, chemicals, and plastics. A database of electron-driven CO_2 reduction pathways is available on an NREL database (NREL 2022), where technoeconomic assumptions and models are published. Because the commercial viability of pathways is highly dependent on the technical performance (state of technology), price of electricity, and market drivers such as the price of CO_2, the database offers current, future, and theoretical scenarios. Pathways include microbial electrosynthesis, high-temperature and low-temperature electrolysis, thermochemical conversion, and biological conversion.

No such database or recommended methodology is available for the use of CO_2 for EW. Therefore, an approach is presented in this report.

The geologic storage potential for CO_2 in the United States has been studied and compiled in several assessments, including by Gray (2010) and Board and NASEM (2019). These assessments leverage decades of experience of CO_2 injection for enhanced oil recovery and several commercial projects involving injection of CO_2 into saline formations. Although the actual amount of CO_2 that can be stored is uncertain, the Atlas estimates onshore US capacities of as much as 107.8 billion MT of CO_2 storage in oil and gas reservoirs, and as much as 13,406 billion MT of CO_2 storage in saline formations. Details on risks, costs, and overall formation integrity are relatively well understood.

The Atlas uses a general approach for estimating CO_2 storage potential. It is as follows:

$$\text{Storage} = \text{total area} * \text{gross formation thickness} * \text{porosity} * \text{density } CO_2 * \text{storage efficiency} \quad (4\text{-}6)$$

The efficiency factor accounts for the fraction of pore space that can displace existing fluids and is available for CO_2 storage. Typically, sites are of interest if they can provide 50–100 MMT of storage at high injection rates (million metric tons per year). Sites also must have a caprock seal that can ensure CO_2 is retained in the formation. Local factors such as faults, trapping mechanisms, risk of fractures, existing wells, and leakage pathways are all characteristics that can be captured in existing numerical models of formations and CO_2 injection and flow (DOE-NETL 2017c). Some models require extensive amounts of data and computational resources that may not be available. Reduced physics models offer an alternative for predicting plume migration.

4.3 NUCLEAR POWER

This analysis characterizes suitable area for large and small reactors. For this study, a large reactor is an LWR with a nominal output of 1,600 MWe and can be accommodated on a 500 acre footprint. In general, this plant size bounds all large Generation III (Figure 4-8) plant designs under consideration by NRC. A small reactor, on the other hand, is a reactor with a nominal output of 350 MWe and can be accommodated on a 50 acre footprint. Microreactors that are designed for off-line applications such as microgrids have a nominal output of up to 20 MWe. They are often portable and do not have significant footprint on land.

Population densities of greater than 500 persons/mi^2 begin to transition into an urban setting. Siting guidance recommends calculating the population density within 20 mi of the site and excluding population densities of greater than 500 persons/mi^2. In addition, nuclear plants must consider seismic restrictions, proximity to fault lines, and nearby hazardous facilities as a public safety issue. Protected lands are excluded based on their definition. Figure 4-8 shows the exclusion areas based on population density of 500 persons/mi^2 within 20 mi. In the following figures, magenta indicates the exclusion areas, and the brown dots indicate mine land locations. Overall, mine land located in urban areas is likely not viable candidate for powering with nuclear energy.

Figure 4-8. Large/small reactor high population exclusion areas.

Figure 4-9 shows the exclusion areas based on susceptibility to landslide hazards; specifically, land with a moderate to high landslide hazard susceptibility is excluded. Figure 4-10 shows the exclusion layer for areas characterized as wetlands and open water. These exclusion areas are mostly on the eastern side of the state.

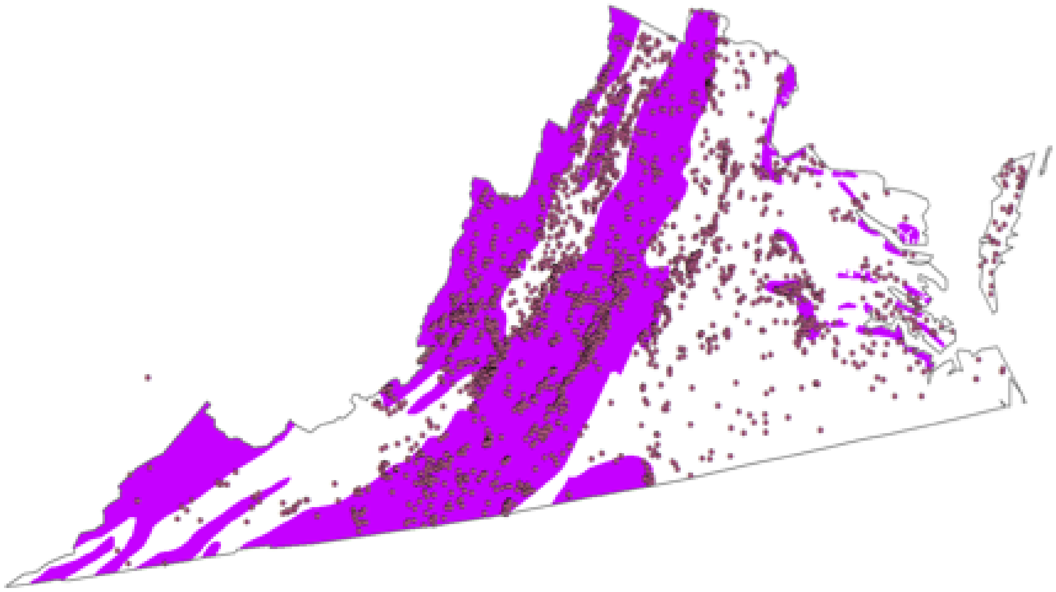


Figure 4-9. Large/small reactor landslide hazards exclusion areas.

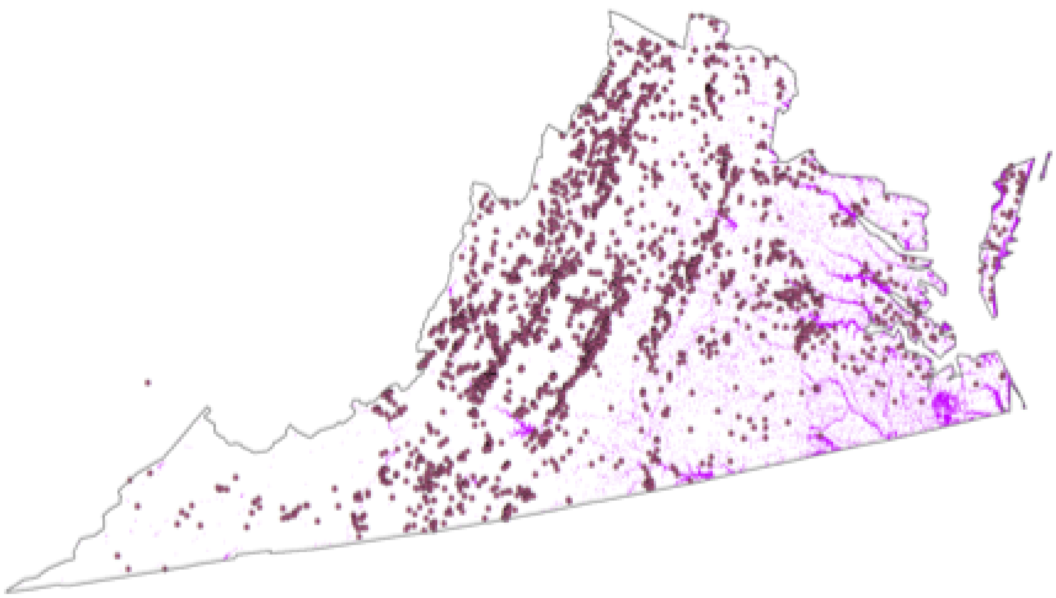


Figure 4-10. Large/small reactor wetlands and open water exclusion areas.

Figure 4-11 shows areas excluded because they have steep slopes; specifically, they have slope greater than 12%, which is approximately 7°. Most of the excluded areas for this criterion are on the western side of the state.

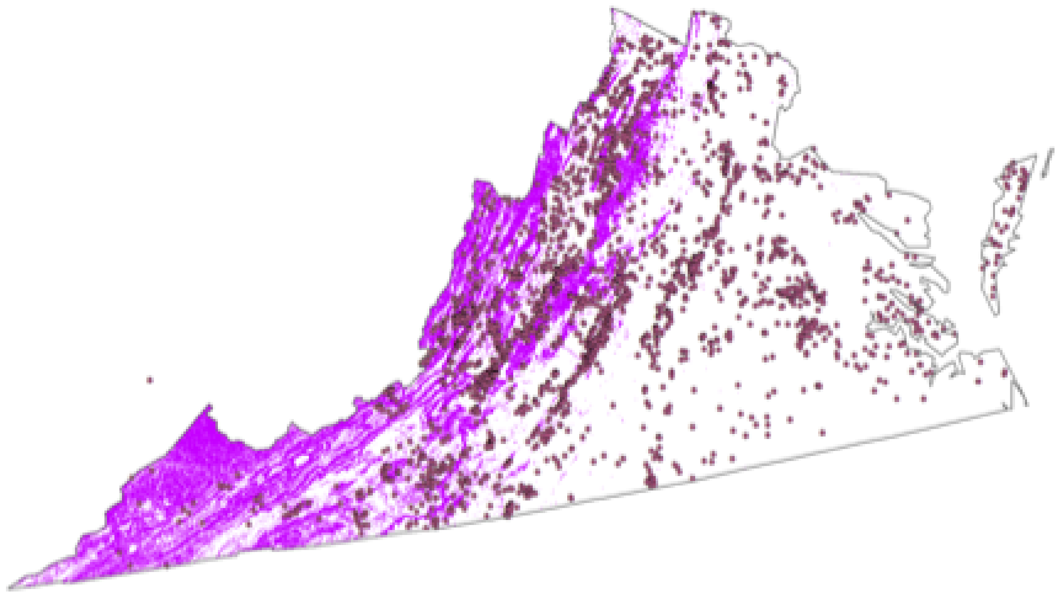


Figure 4-11. Large/small reactor high slope exclusion areas.

Figure 4-12 shows excluded land that are characterized as protected lands. Protected land includes national parks, historic areas, and wildlife refuges.

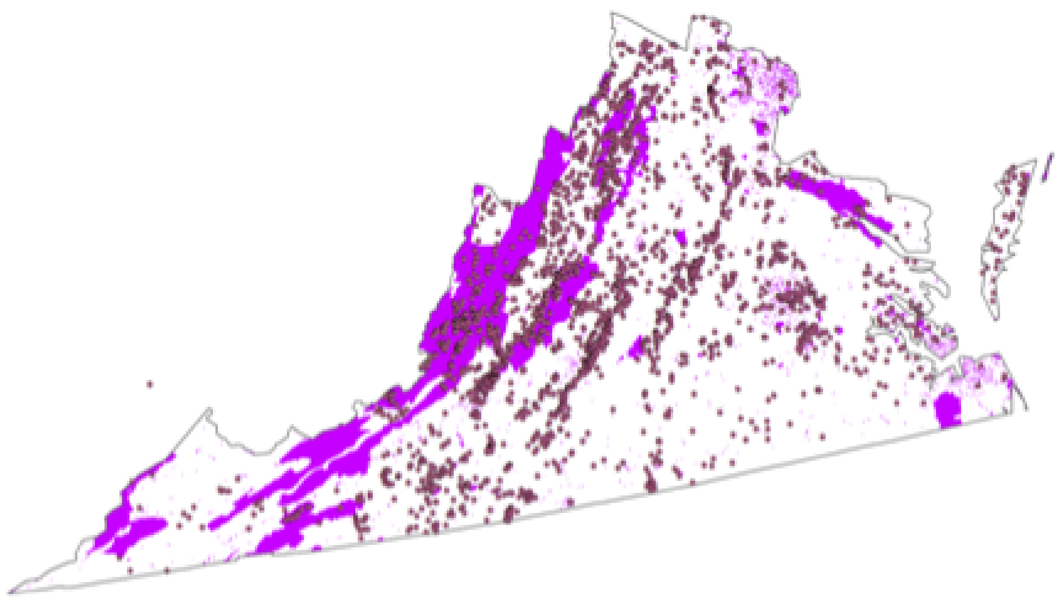


Figure 4-12. Large/small reactor protected lands exclusion areas.

Figure 4-13 shows the composite layer obtained if all these exclusion layers are put together. The green areas did not flag any of the criteria; yellow areas flagged one criterion; orange areas flagged two criteria; and blue areas flagged three or more criteria. Overall, there are several mine land sites on green areas all over the state, and especially on the eastern side.

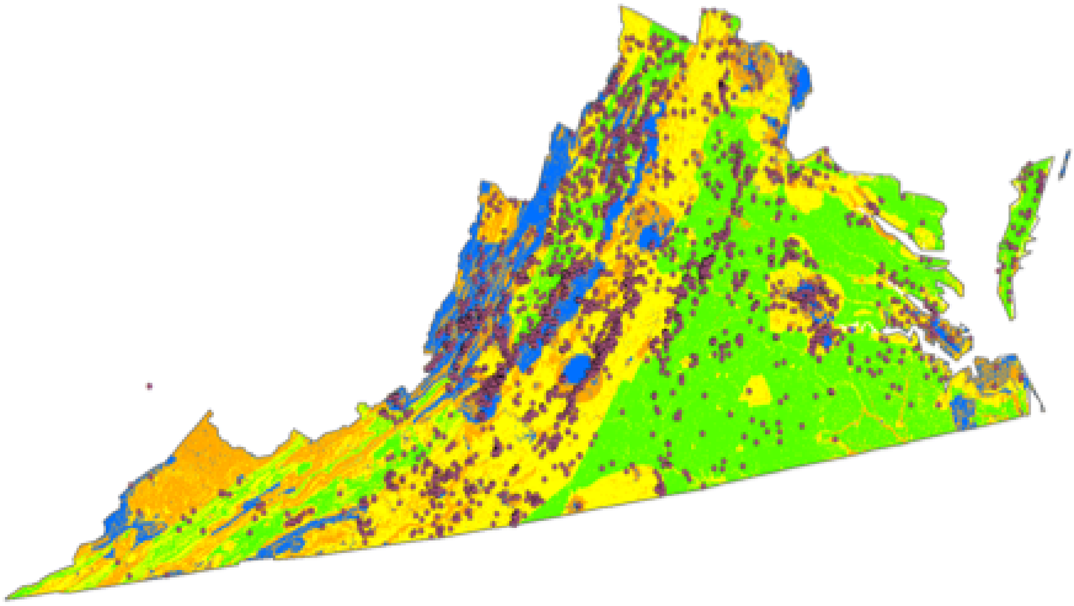


Figure 4-13. Large/small reactor composite map based on selected criteria.

4.4 PUMPED STORAGE HYDROPOWER

As stated in Section 2, the reservoir storage volume, water flow rate, and hydraulic head are key variables in determining power potential. Economic viability follows economies of scale, with higher megawatt projects having lower per-kilowatt costs. Thus, a 1 GW project is likely to have a much lower cost per kilowatt compared with a 100 MW project. As suggested in Hadjerioua et al. (2020) and illustrated in Figure 4-14, the average capital cost can almost halve in value as the size of the project increases.

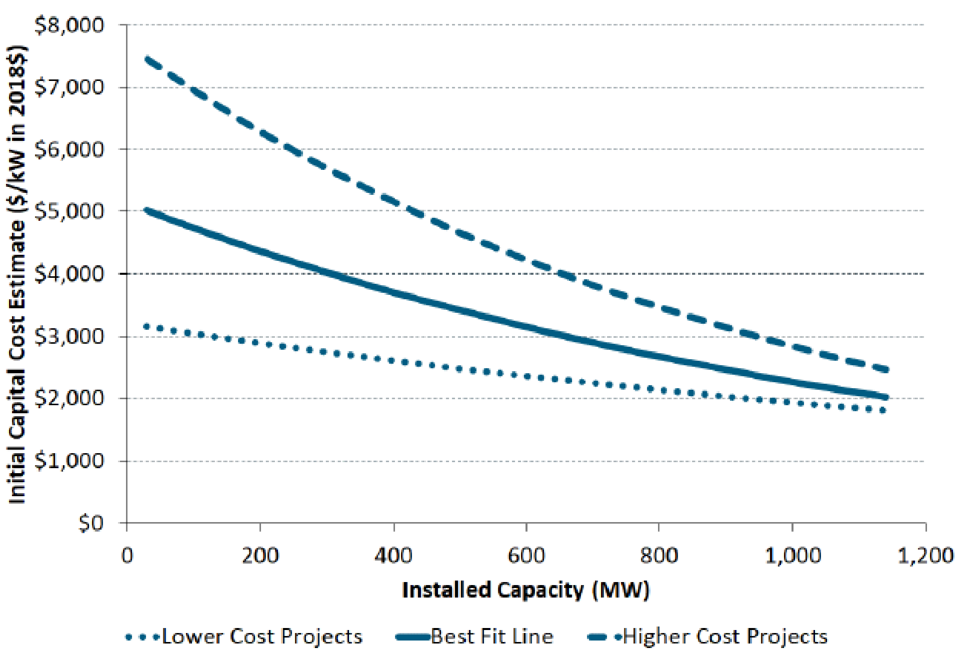


Figure 4-14. Preliminary ICC estimates for PSH in 2018 dollars. Source: Hadjerioua et al. (2020), based on megawatt hours (2009).

Reservoir storage volume

The first criterion to consider is the total volume of water that can be used for generation. This parameter is constrained by the physical site characteristics present at a mine, including the geologic stratification which may be conducive to excavation and construction. Manufactured PSH reservoirs are typically semi-conical in nature, with storage being a function of maximum water depth, full-pool area size, reservoir bottom area size, and embankment slope.

Existing research shows that the capacity costs of PSH on an open pit coal mine decline substantially as volume increases from 1 megaton to 5 megatons, and then levels off as volume reaches 8 MT or above, and NPV consistently increases with the increase of the storage volume (Wessel et al. 2020).

Water flow rate

Water flow rate is constrained by the smallest of the upper reservoir storage volume and the lower reservoir storage volume. The other parameter to consider is the desired power generation duration. Typically, most PSH projects operate on a daily basis, generating power for 4–10 h (Kortarov et al. 2022) and using additional time during the day to return water to the upper reservoir.

A simplified calculation of total water flow rate can be performed according to Eq. (2-1). Total flow rate may be split among different penstocks to supply multiple pumps/turbines (or reversible pump-turbine units).

Water hydraulic head

The water hydraulic head varies as the upper and lower reservoirs are filled and emptied. Hydraulic head is measured as the elevation difference between the upper and lower reservoir surface water elevation, minor energy losses and water flows through the water conveyance system.

Estimated installed (power) capacity

The turbine(s) and pump(s) installed in a PSH powerhouse are sized to meet the design head and flow for each unit. The power generated by an individual turbine is a function of water density, flow rate, gravity, and head, as calculated in Eq. (2-2).

4.5 GEOTHERMAL ENERGY AND SUBSURFACE THERMAL ENERGY STORAGE

This section discusses resource distribution within the United States, and estimation methods for geothermal energy and subsurface thermal energy storage potential.

4.5.1 Geothermal Resource Distribution in the United States

4.5.1.1 Link between ore deposits and geothermal systems

Hydrothermal ore deposits, especially those associated with epithermal (shallow) systems, and geothermal systems are often closely related. Both types of systems require a heat source, fluids, and flow pathways. Epithermal ore deposits represent the mineralized remnants of fossil hydrothermal systems (e.g., White 1981, Henley and Ellis 1983, Hedenquist and Lowenstern 1994, Bogie et al. 2005, Boden 2017). Modern geothermal systems can serve as analogues that can be used to develop exploration models for hydrothermal ore deposits (e.g., White 1981, Brown and Simmons 2003). Many geothermal brines contain dissolved metals that represent an active ore fluid (e.g., Skinner et al. 1967, McKibben et al. 1988, Gallup 1998, Brown and Simmons 2003, Simmons and Brown 2006, Breit et al. 2011). Thus, a genetic connection often exists between hydrothermal ore deposits and active geothermal systems. Figure 4-15 shows such an example. The McLaughlin Au mine in northern California was discovered using an exploration model based on the Broadlands geothermal system (e.g., Gustafson 1991, Sherlock 2005). In most cases, the hydrothermal systems associated with the ore deposits are no longer active, and these systems represent fossil geothermal systems that no longer retain much of their thermal resources. However, some instances occur where young ore deposits are associated with active geothermal systems.

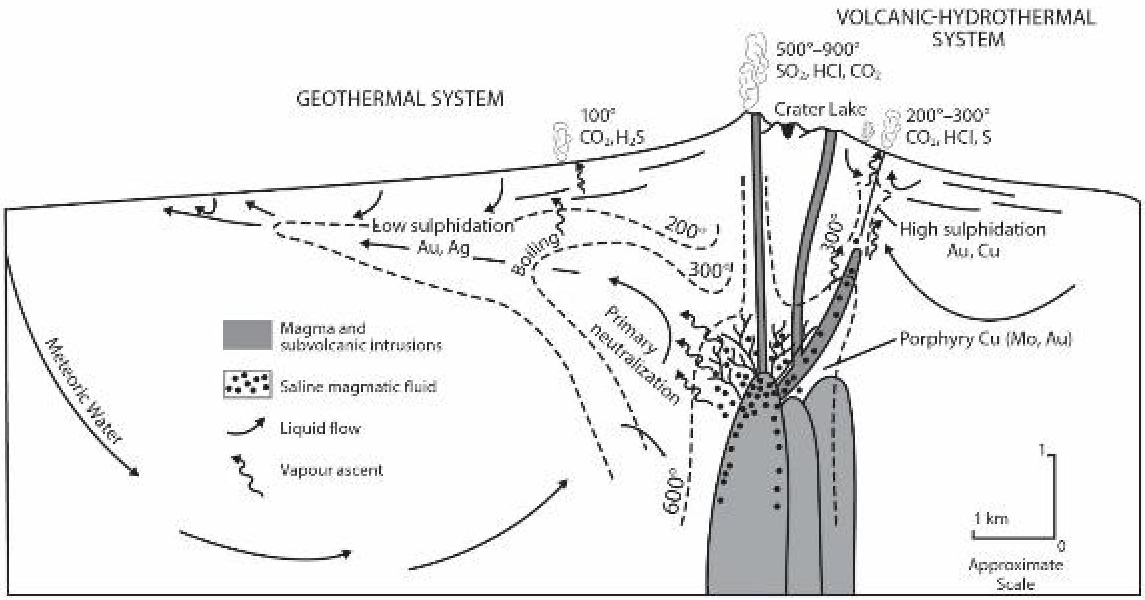


Figure 4-15. Schematic cross section depicting an active geothermal system in an arc volcanic terrane with associated epithermal hydrothermal ore deposits (Hedenquist and Lowenstern 1994).

The most dramatic example of the link between epithermal ore deposits and active geothermal systems is the Ladolam geothermal system on Lihir Island in Papua New Guinea (Simmons and Brown 2006, White et al. 2010, Cooke et al. 2020), as shown in Figure 4-16. This world-class Au deposit is co-located with an active geothermal system whose development helps to depressurize the mineral deposits, thus reducing the risk of hydrothermal eruptions. The geothermal system also provides electricity to power the mine's infrastructure. An initial 6 MW geothermal power plant was installed in 2003, followed by a 30 MW expansion in 2005. An additional 20 MW of capacity was added in 2007, resulting in an overall power generation capacity of 56 MW (Maennling and Toledano 2018).

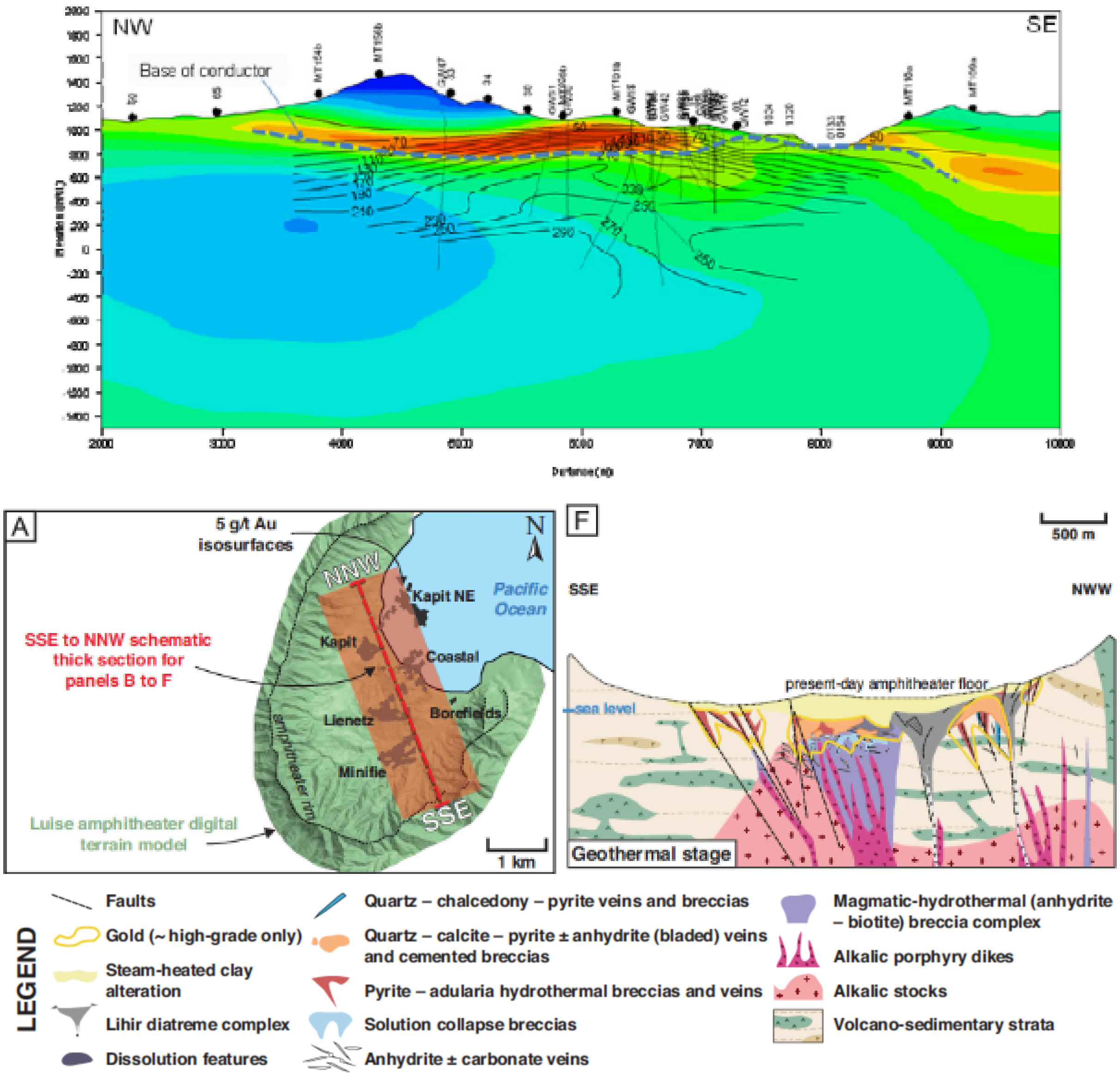
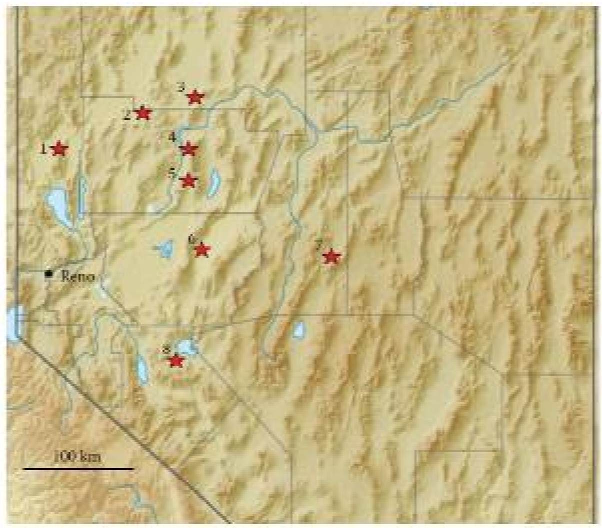


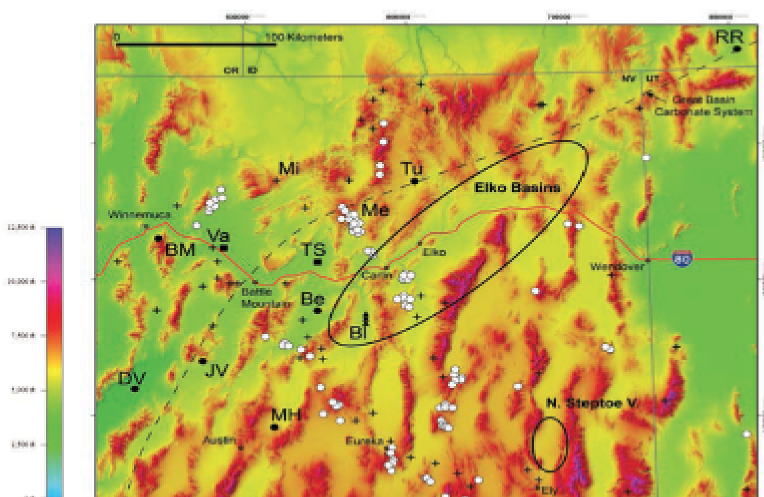
Figure 4-16. Upper (White et al. 2010): northwest–southeast cross section through the Lihir Au mine and Ladolam geothermal system, depicting the geothermal wells, isotherms, and color shading that reflects differences in electrical resistivity (hot colors are conductive, cold colors are resistive). Bottom left (Cooke et al. 2020): Plan view map of digital terrane model, along with location of the main Au ore zones. Bottom right (Cooke et al. 2020): south-southeast–north-northwest cross section depicting the currently active geothermal stage of the system, with a steam-heated clay alteration zone capping some of the underlying features.

Geothermal systems and ore deposits in Nevada

A number of studies have noted the coincidence between the location of geothermal systems and mineral deposits in Nevada (e.g., Miller and Flynn 1992, Faulds et al. 2005, Coolbaugh et al. 2005, 2011, Hunt et al. 2011, Simmons and Allis 2015, Boden 2017) (Figure 4-17). Many of the currently producing geothermal fields in Nevada are called hidden systems; that is, they do not have associated thermal features present at the surface (Dobson 2016). Most of these developed hidden geothermal systems (e.g., McGinness Hills, Blue Mountain, Don A. Campbell, and Tungsten Mountain) were discovered in part by companies exploring for mineral resources and encountering hot water instead of commercially viable mineral resources during exploration drilling operations (e.g., Casaceli et al. 1986, Parr and Percival 1991, Fairbank and Ross 1999, Waibel et al. 2003, Vikre and Koutz 2013, Orenstein et al. 2015, Dobson 2016, Levine et al. 2022). The presence of hydrothermal alteration, sinter deposits, and elevated shallow temperatures have served as key indicators for the presence of hidden geothermal resources at depth. Although many commercial epithermal mineral deposits in Nevada are tertiary in age and therefore have fossil hydrothermal systems, at least one Au mine (Florida Canyon) is associated with an active hydrothermal system (Rye Patch).



(a)



(b)

Figure 4-17. (a) Map of northwest Nevada showing locations of geothermal power plants and precious metal deposits: (1) Wind Mountain/San Emidio, (2) Hycroft, (3) Blue Mountain, (4) Florida Canyon/Rye Patch, (5) Willard/Collado, (6) Dixie Comstock, (7) McGinness Hills, and (8) Don A. Campbell (Boden 2017). (b) Map of northeast Nevada showing locations of geothermal power plants (black circles: Be = Beowawe, BM = Blue Mountain, DV = Dixie Valley, JV = Jersey Valley, MH = McGinness Hills, RR = Raft River, and TU = Tuscarora), hydrocarbon-fueled power plants (black squares), Carlin-type Au deposits (white circles), and intrusion-related and epithermal deposits (crosses) (Simmons and Allis 2015).

4.5.1.2 Temperature distribution

An important parameter for geothermal resource evaluation is the water temperature, which applies for all types of applications discussed in Sections 2 and 3.

A geothermal resource map with identified hydrothermal sites and favorability for EGSs (Figure 4-18) was developed by NREL,[40] which could be used as a general guide for understanding high-temperature geothermal resources. Although high-temperature geothermal resources are typically related to deep subsurface, they are considered here for evaluation of potential geothermal resource below a mining site. Low-temperature geothermal resource potentials at six depths (Mullane et al. 2016) are shown in Figure 4-19.

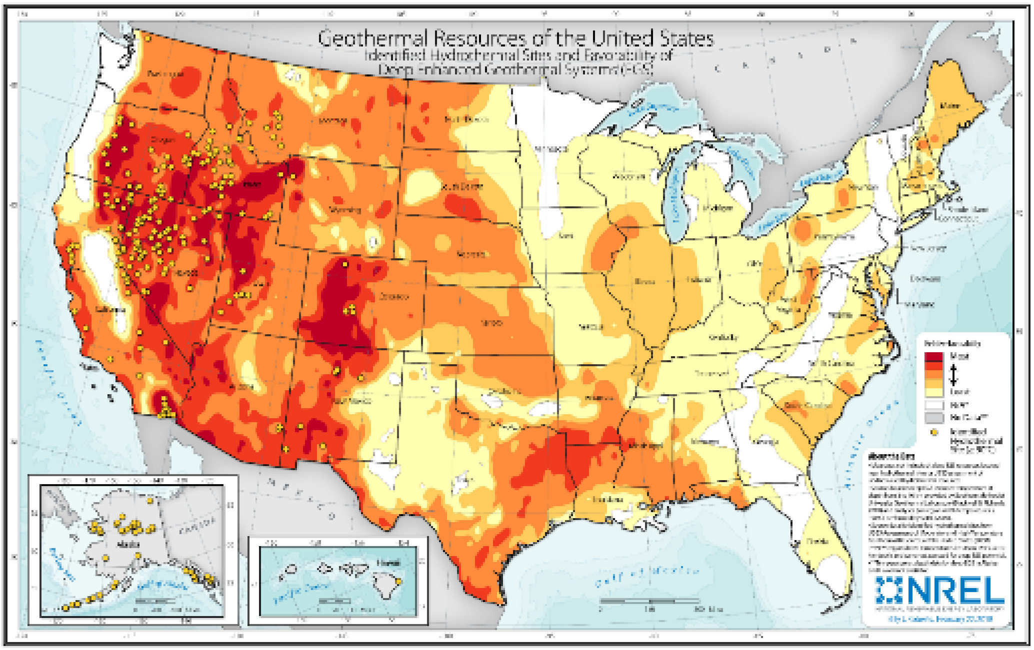


Figure 4-18. Geothermal resources of the United States showing the hydrothermal sites and favorability of deep EGSs (Credit: NREL[41]).

[40] https://www.nrel.gov/gis/assets/images/geothermal-identified-hydrothermal-and-egs.jpg
[41] https://www.nrel.gov/gis/geothermal.html

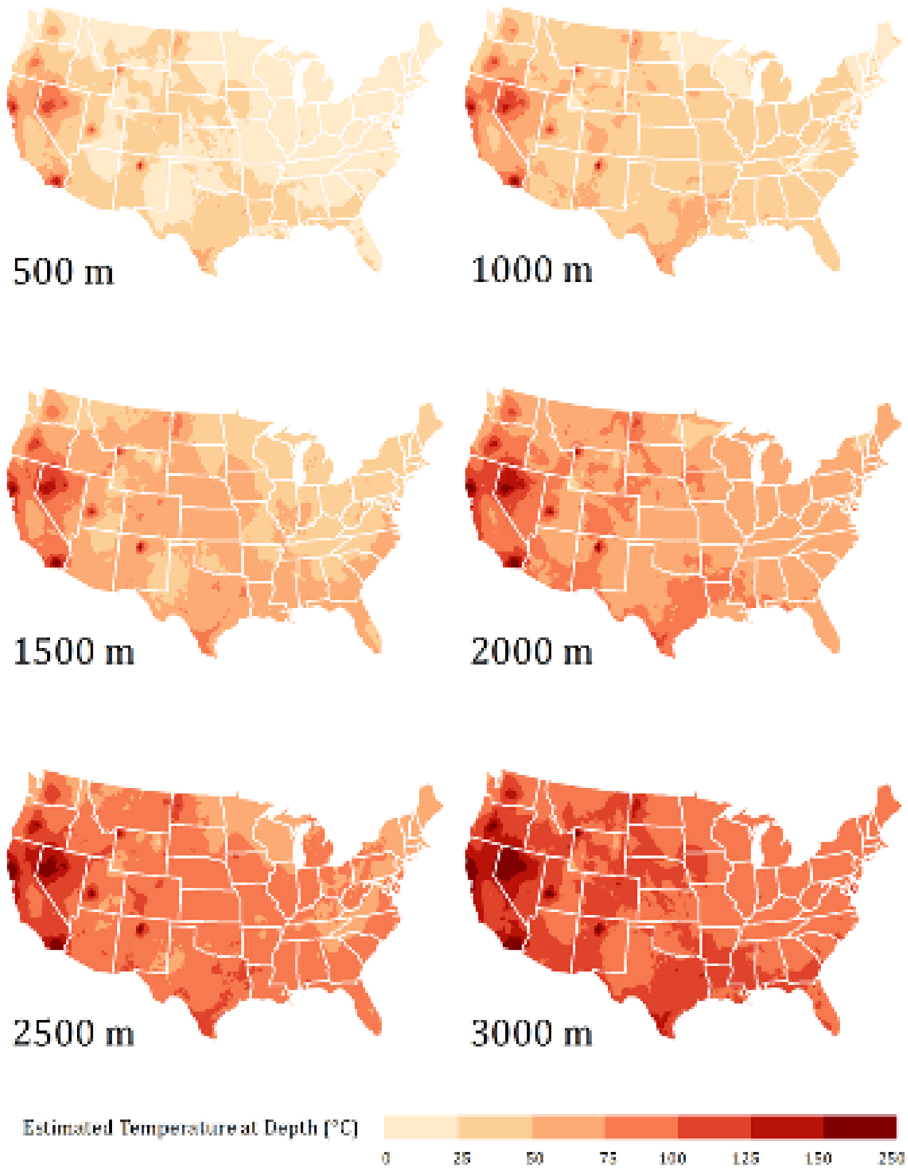


Figure 4-19. Estimated temperature across the United States at six depths (credit: Mullane et al. 2016).

Geothermal resources in the western United States

USGS has also conducted high- and low-temperature geothermal resources assessments of the United States (e.g., Godwin et al. 1971, Muffler 1979, Reed 1983, Williams et al. 2008b) and identified prospective and known geothermal resource areas, along with the favorability of geothermal resources within the western United States (Figure 4-20). Extensive amounts of relevant data related to geothermal resource characterization throughout the United States are provided on the Geothermal Data Repository (e.g., Weers et al. 2022).[42] Additional data are also available in the published literature and in state and USGS reports and data archives.

[42] https://gdr.openei.org/

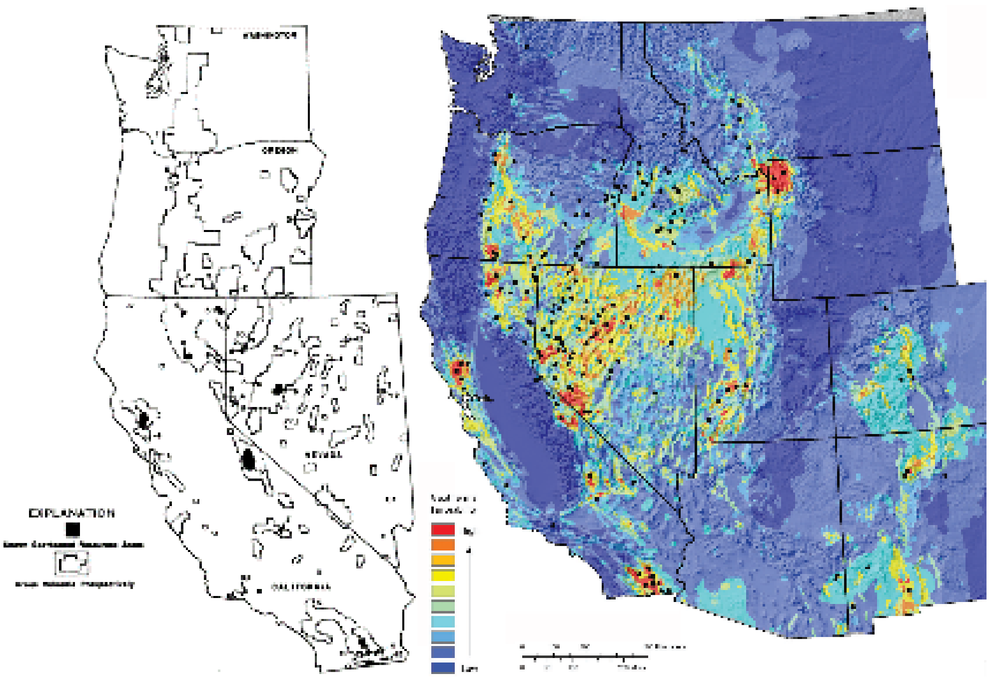


Figure 4-20. (left) Map of prospective and known geothermal resource areas in California, Nevada, Oregon, and Washington (Godwin et al. 1971); and (right) favorability map of high-temperature geothermal resources. Warmer colors indicate higher favorability (Williams et al. 2008b), and black dots indicate the locations of identified moderate- and high-temperature geothermal systems.

For power generation, typically, a minimum temperature of 150°C is required unless a binary cycle is used, in which a minimum temperature of 95°C is needed.

4.5.2 Estimation Methods for Geothermal Energy and Subsurface Thermal Energy Storage Potential

To calculate a relatively accurate estimate of resource potentials, site-specific information needs to be used. This is especially important for technologies deployed in subsurface. The methods described in this section can only be used during the screening period. If a site shows promising potential after the initial assessment, a more rigorous site characterization needs to be performed. In many cases, numerical simulations must be performed using characterized geological information as an input. Subsequent uncertainty analysis is performed to understand uncertain ranges of the predictions.

The temperature at a site is one of the most important factors determining the resource potential. The maps provided in Figure 4-19 can be used to provide an estimate if there are no local measurements. Once a site is selected, local measurements need to be made to understand site temperature and heat flow and thermal properties of the host rock. Another key parameter to estimate the resource potential is the mine water volume, as well as backfill volume if the energy stored in the back filling material is considered. Jessop et al. (1995) provided two methods to calculate mine water volume without considering backfill. The two methods presented here are modified to include the backfill volume. In the first method, the total produced volume is estimated by multiplying the area mined in each seam and the average thickness of the seam. Then, the volume is adjusted by subsidence of the roof (i.e., using a coefficient R_s in Eq. (4-7)). Assuming a backfill ratio of R_b, the mine water volume (Eq. (4-7)) can be calculated as

$$V_f = R_s * (1 - R_b) * \sum_{i=1}^{n} A_i * h_i \,, \tag{4-7}$$

where A_i is the area of a seam (m^2), h_i is the average thickness of the seam (m), and n is the total number of seams. The backfill volume (m^3) can be calculated in Eq. (4-8):

$$V_b = R_s * R_b * \sum_{i=1}^{n} A_i * h_i \; . \tag{4-8}$$

The second method is based on product mass M (kg) and ore density ρ (kg/m^3):

$$V_f = R_s * (1 - R_b) * M/\rho \; , \tag{4-9}$$

and

$$V_b = R_s * R_b * M/\rho \; . \tag{4-10}$$

Geothermal power generation

Rubin et al. (2021) summarized two geothermal resource estimation methods to generate geothermal power generation potential. The first one is a modified USGS volumetric heat-in-place method (e.g., Williams et al. 2008a). It first calculates the total energy (heat) stored in a geothermal reservoir, which is the summation of the heat from the rock and heat from the fluid (steam and liquid) within the rock pore space. Then, the actual amount of the energy that can be extracted by power plants is estimated based on total plant operating time within its lifetime and some efficiency/conversion factors.

The second method is the power density method. The capacity is expressed by power per area (MW/km^2). Wilmarth and Stimac (2015) compiled data from 66 geothermal fields and established a correlation between power density and reservoir temperature, interpreted in terms of tectonic setting and production history. The method is relatively simple to use, but the data points used to derive the relationship were not from geothermal resources on mine land, so it is not clear how applicable it is for estimating geothermal capacity on mine land.

However, a more likely scenario is that a higher-temperature resource may lie beneath an existing mine, and that deep geothermal wells are drilled to access this resource. In that case, more typical geothermal resource estimate methodologies could be applied to assess the generation potential of such a resource (e.g., Cumming 2016), in which a variety of geologic, geochemical, and geophysical data are used to estimate the resource temperature and volume (e.g., Harvey et al. 2014) through the development of conceptual models of the resource (Figure 4-21).

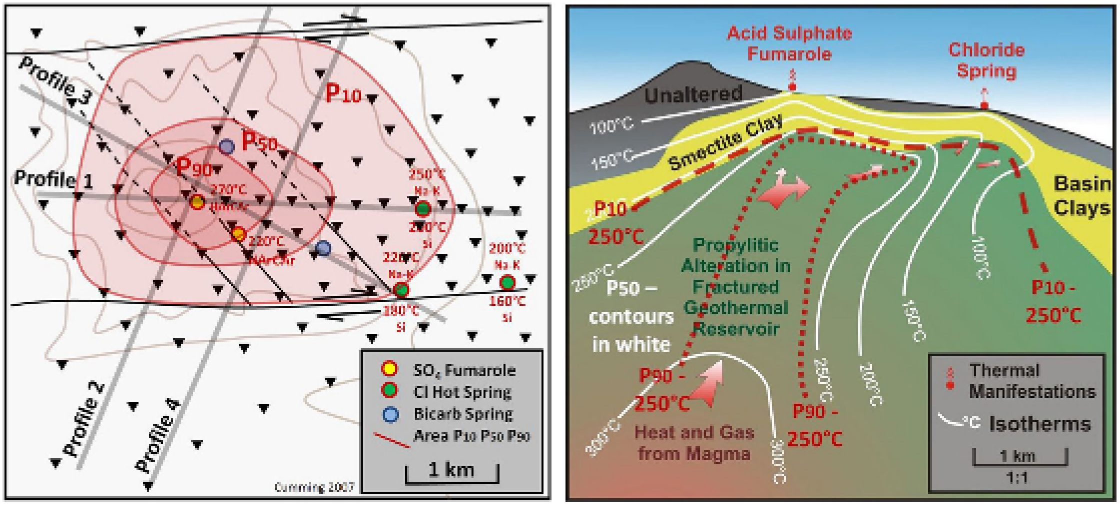


Figure 4-21. Conceptual model of a hypothetical geothermal resource with different confidence contours (P10, P50, and P90) depicting the location of the 250°C isotherm. Resource temperature estimates are derived from a variety of geothermometers using spring and fumarole chemistry data (Cumming 2016).

4.5.3 Geothermal Resources for Direct Use and Process Heating and Cooling Applications

The basic concept to evaluate the geothermal resource potential for direct use applications (including heating and cooling) is similar to geothermal power generation applications. The thermal energy available to be used can be estimated based on how much heating (cooling) was in place (Comeau et al. 2021):

$$P_n = \frac{Q_T}{t} = (V_f * \rho_f * C_f * \Delta T * R_{br})/t \,, \tag{4-11}$$

where P_n is the thermal power from the mine (kW); V_f is water volume calculated from Eq. (4-9), ρ_f and C_f are mine water density (kg/m^3) and specific heat (kJ/kg·°C), respectively; t is the total time of operation (energy extraction), and R_{br} is the correction coefficient for the bedrock (to account for the heat exchange between the mine water and the bedrock). Comeau et al. (2021) used 25 for underground mines and 1.25 for open pit mines.

ΔT is the usable temperature difference. For example, if the temperature of the fluid at the wellhead is 50°C, its temperature is 47°C before it enters the heat exchanger, and it becomes 30°C after it is out of the heat exchanger, then ΔT is 17°C, not 20°C. The beneficial heat concept (usually expressed as a portion, such as 60% of the temperature difference between the wellhead and reference temperature) in low-temperature geothermal applications is already embedded in this formulation.

If a GHP system is used for efficient heating and cooling, then the geothermal energy generation capacity (P_{tot}, kW) can be calculated as Eq. (4-12) for heating and Eq. (4-13) for cooling.

$$P_{tot} = P_n + P_{hp} = P_n + P_n/(COP - 1) \,, \tag{4-12}$$

$$P_{tot} = P_n - P_{hp} = P_n - P_n/(COP + 1) \,, \tag{4-13}$$

where P_n is the thermal power from the mine calculated from Eq. (4-11), P_{hp} is the electrical power consumed by the heat pump (kW), and COP is the coefficient of performance defined as the ratio between the rate at which the heat pump transfers thermal energy (P_{tot}, kW) and the amount of electrical power required to do the pumping (P_{hp}, kW).

Systematic geothermal resource estimates for direct use heating applications have been conducted for flooded abandoned mines in Ohio (Richardson et al. 2016); Quebec and Nova Scotia (Arkay 2002); and the Pittsburgh coal seam in Pennsylvania, Ohio, and West Virginia (Watzlaf and Ackman 2006). Each of these studies examined the inventory of mines in their study area and employed a unique methodology for assessing the potential for heating, but these approaches all included the volume of water in the mine, the temperature of the mine water, and the change in temperature that would determine the amount of thermal energy that would be extracted from the flooded mine. The effects of thermal recharge from surface infiltration and groundwater flow were also considered. The types of information needed for developing an assessment of the geothermal potential of each mine consists of the following (e.g., Arkay 2000):

- Mine location
- Type of mine and mining methods used
- Mine depth
- Geometry and volume of underground workings
- Abandonment status and features
- Availability and reliability of mine schematics
- Underground temperatures
- Mine water chemistry
- Mine hydrology
- Current land use status

4.5.4 Subsurface Thermal Energy Storage

Similarly, the total potential thermal storage capacity (in terms of energy, kJ) at a mine site can be estimated as

$$Q_t = (V_f * \rho_f * C_f * \Delta T) \,, \tag{4-14}$$

where ΔT is the heating/cooling load (°C). The thermal power added to the mine water can then be calculated based on duration of injection/production periods.

The recovered energy after storage will be less than stored energy because of heat loss to the bedrock. The proportion of the available energy to be recovered compared with the stored energy is defined as the system efficiency when expressed using the average heat flux:

$$\lambda = \frac{q^{out}}{q^{in}} = \frac{q^{in} + q_{geo} - q_{bedrock}}{q^{in}} \,, \tag{4-15}$$

where $q^{in} = Q^{in}/t$ is the average heat flux to be stored. Initially, $Q^{in} = Q_t$. q_{geo} is the geothermal heat into the system, which might be estimated from the most recent USGS heat flow map (Williams and DeAngelo 2015). $q_{bedrock}$ is the heat flux to the bedrock. The average heat flux to bedrock over the first storage period is highest in the first cycle because the temperature difference between the bedrock and injected fluid is the highest. Over time, the bedrock temperature will gradually get closer to the fluid temperature. As a result, the thermal storage capacity will lower, but the system efficiency will increase.

4.5.5 Mineral Recovery from Geothermal Fluids and Fluids associated with Mine Land Sites

The development of ancillary resources to form a hybrid geothermal project can result in improved project economics as well as decarbonization of mineral recovery technologies. Geothermal brines have a wide range of fluid compositions depending on the sources of the fluids (magmatic, meteoric, and formation waters), the reservoir rock types, and the temperatures of the systems. Although many geothermal fluids have relatively low (<10,000 ppm total dissolved solids), some geothermal brines have significantly higher salinities and also contain elevated concentrations of dissolved critical minerals. Saltwater battery is another type of resource potential but is outside the scope here. Neupane and Wendt (2017) and Simmons et al. (2018) conducted analyses of geothermal brines and reviewed published values from a wide range of geothermal systems across the western United States to identify the potential mineral resource base of these fluids. They noted that although all geothermal fluids have elevated concentrations of silica that could potentially be recovered for economic purposes, only a few geothermal systems had high enough concentrations of other constituents (such as Li, Zn, Mn, and K) to make them viable targets for mineral recovery.

The most prospective geothermal fluids that were studied were the hypersaline (approximately 25 wt % dissolved solids) brines from the Salton Sea geothermal field. These brines have been the subject of numerous attempts for mineral recovery (e.g., Morton 1977, Maimoni 1982, Clutter 2000, Featherstone et al. 2015), given the large potential dissolved mineral resources that they contain, which has been estimated to represent 15 MMT of Mn, 5 MMT of Zn, and 2 MMT of Li (McKibben et al. 2021). However, these efforts have been hampered by the difficulty of working with such highly saline, high-temperature fluids. With increasing demand (and commodity prices) for Li, three companies (Berkshire Hathaway Energy Renewables, Energy Source Minerals, and Controlled Thermal Resources) are currently attempting to develop commercial-scale processes for direct Li extraction at the Salton Sea geothermal field. Notably, the high dissolved mineral content found in the Salton Sea geothermal brines is not representative of most geothermal fluids, and the potential for mineral extraction from geothermal brines will depend on the fluid composition of each specific resource. Resource estimates can be made using two general approaches: (1) a resource-in-place estimate based on the volume of the geothermal reservoir (areal extent times reservoir thickness times porosity) and the average concentration of the dissolved mineral constituent in the brine; and (2) the amount of brine being produced in existing wells, the amount of dissolved constituent in the brine, and a mineral extraction efficiency factor (this approach constitutes a produced amount, which would decline over time as the mineral is recovered from the geothermal reservoir).

All mine sites (both open pit and underground mines) have water, which has dissolved constituents derived from the rocks or minerals being mined. In open pit mines, water can collect in the excavated pits and tailing ponds, and most underground mines require pumping to prevent the mine from being flooded by infiltrating water. Many mines have to manage large quantities of water, which often includes water treatment to remove harmful constituents. For example, at the Sanford Underground Research Facility (the former Homestake Mine in Lead, South Dakota), the facility pumps approximately 700 gpm to maintain the water level in the mine at the 5700 level (i.e., 5,700 ft underground). The warm (approximately 37°C) pumped water is mixed with nearly equal amounts of cold water from a surface tailings pond to bring the water to an acceptable temperature for ideal bacteria conditions, and this mixed water is then filtered, mixed with a coagulant and flocculant to remove Fe in a sludge tank, passed through 19 rotating biological contactors to remove NH_3 and heavy metals, and filtered one more time before it can be discharged safely into a local stream (SURF 2022). In Butte, Montana, cessation of underground mining and pumping in 1982 led to the flooding of the Berkeley Pit, where almost 50 billion gal of water have accumulated. Underground mining was suspended, but Cu was still being recovered from the low-pH fluids from the Berkeley Pit for several decades (Duaime and McGrath 2019).

Acid mine drainage (AMD) is a major concern for many abandoned mines, where low-pH waters, which commonly contain high levels of hazardous constituents, are often discharged into surface waters. However, some of these fluids contain dissolved constituents that may be valuable to recover. The aqueous complexation of REEs with sulfate at low pH together with the naturally extreme leaching character of acidic solutions can result in a significant enrichment of these elements in AMD, up to near parts per million levels, both from sulfide ore deposits (e.g., Miekeley et al. 1992, Verplank and Nordstrom 1999, Protano and Riccobono 2002, Verplanck et al. 2004, Wood et al. 2005) and coal seams (e.g., Zao et al. 2009) and their associated tailings in mined areas. The precipitation of Fe (oxy) hydroxides upon neutralization of these fluids and the strong surface adsorption of rare earths onto these phases at intermediate and higher pH (Verplanck et al. 2004, Tang and Johannesson 2005) could provide a means of both mineral recovery and groundwater remediation (Ayora et al. 2015a, 2015b).

Iron Mountain, a massive sulfide ore deposit mined from the 1880s until the 1960s, was the largest Cu producer in California. The area was also mined for Fe, Ag, Au, Zn, and pyrite. It was designated a Superfund site by EPA in 1982 after years of acidic effluents from several mines, loaded with Cu and other metals, heavily contaminated surrounding creeks and the Sacramento River, and regularly resulting in fish kills (Alpers et al. 1992, Nordstrom and Alpers 1999). EPA estimated that Iron Mountain discharged (prior to remediation), on average, 650 lb of Cu, 1,800 lb of Zn, and 10,000 lb of Fe per day and was the largest AMD discharge to surface waters in the nation identified under the Clean Water Act (EPA 2006). The existing lime neutralization plant at Iron Mountain (and other similar treatment systems at other AMD sites) could serve as useful sites to investigate the transport, deposition, and recovery of REEs in AMD. Other mine sites that have AMD may also have the potential for recovery of REEs from these mine waters as part of the treatment process.

In summary, to estimate geothermal resource potential regardless of the application type, the temperature at the mine site and the volume of mine water must be understood. Other uncertainties come from the interactions (heat exchange) with bedrock, recharge, discharge conditions, and engineering designs (e.g., wells, power plants) for energy extractions. Ancillary resources, such as dissolved minerals in brines, can help improve the economics of these hybrid projects.

4.6 COMPRESSED AIR ENERGY STORAGE

4.6.1 Storage and Power Capacity

Before discussing the potential for CAES in underground mines to support the US electricity grid, it is important to understand two storage concepts: energy storage capacity and power capacity. Briefly, energy storage capacity is the amount of energy in units such as Joules or megawatt hours that can be stored. Storage capacity is important because it is the long-term energy supply that can be provided during multi-day periods of cloudy and calm weather, or during extreme cold or hot periods when large amounts of heating or cooling are needed. The power capacity is the rate at which energy can be stored or recovered and delivered to the grid in units such as watts (1 W = 1 J/s) or megawatts. In general, CAES facilities on the order of 10 MW with less than about 10 h of storage mainly provide values in carbon-free economy and back-up service. (Fosnacht et al. 2015).

For a mechanical energy storage approach such as CAES, the volume available to store the compressed air/gas and pressure correlates directly with the energy storage capacity, and the flow rate of air in and out of the volume correlates directly with the power capacity. The best energy storage systems must have both large energy storage capacity and large power capacity. The power capacity can only be met over time if the storage capacity is met. With these concepts in mind, abandoned underground mines clearly present many favorable features as potential sites for developing CAES facilities.

First, the volume available in abandoned underground mines is enormous relative to energy storage needs. This can be illustrated by examining the volume of coal mined in the United States. Figure 4-22 shows the mass of coal mined at some of the larger US coal mines in 2021. Using an average density of coal, one can estimate the volume of space created underground by the removal of the coal. This volume is conservative in that there is an even larger volume created in the mining process as access tunnels, shafts, and ventilation infrastructure are also excavated at all underground mines. If a coal density of 1,500 kg/m^3 is assumed and 6 million short tons of coal are produced, a void space of more than 4 million m^3 is produced underground just by the removal of the coal. For comparison, the Huntorf cavern CAES facility in Germany produces 321 MW (power capacity) for 2 h per day (642 MWh of energy storage capacity) using a cavern volume of 310,000 m^3 (Budt et al. 2016), one thirteenth the volume of coal removed from just one large coal mine in the United States.

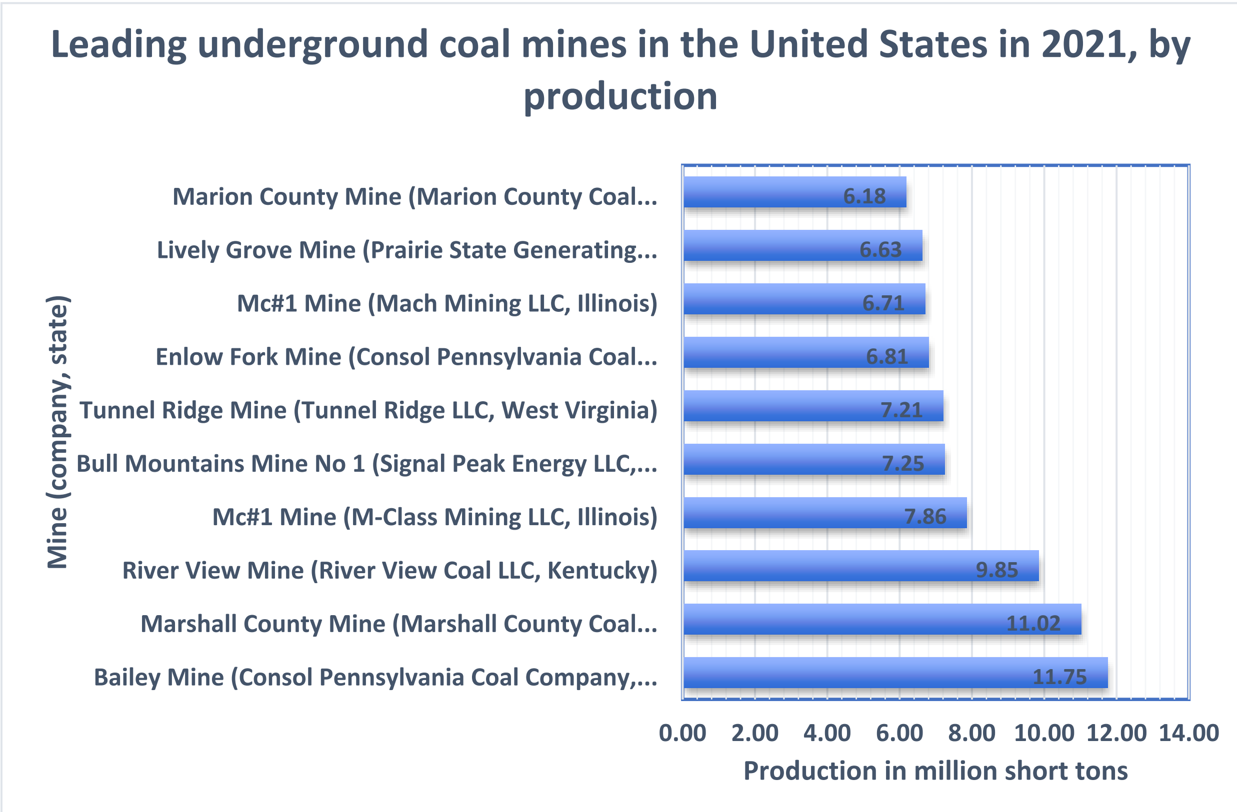


Figure 4-22. Coal production at large underground mines in the United States. Data source: US Department of Labor, EIA, 2021; figure reproduced from https://www.statista.com/statistics/380668/leading-underground-mines-in-the-us-by-production/.

Second, considering the power capacity of mines, the large diameters of shafts, adits, and other access tunnels reaching the ground surface demonstrate that enormous mass flow rates of air are possible from future underground mine CAES facilities. The openings to underground mines can accommodate large volumetric flow rates of air or multiple air ducts inserted into shafts and tunnels. Again, with reference to the cavern CAES facilities in Huntorf, Germany, and McIntosh, Alabama, power capacities of 321 MW and 110 MW, respectively, are achieved using large-diameter wells (approximately 0.61 m in diameter). With typical mine openings on the order of a few meters in diameter (five times larger than the Huntorf wells), airflow rate is not a limiting factor for CAES facilities developed in underground mines. In practice, operators would likely install large-diameter ducts (diameter of approximately 1 m) within the tunnels and shafts to transfer compressed air. The main limitations on power capacity often come from the surface infrastructure in terms of how many turbines and how much related compression and electricity generation infrastructure are installed. Because of the large size of access openings and workings in mines, the mine openings themselves will not be a limiting factor in power capacity.

Because of the large volume and open access tunnels and shafts in mines, the main engineering challenge to developing CAES facilities in underground mines will be more in limiting the airflow and accessible volume than in enhancing it. For example, for a given energy storage project with its specific energy storage and power capacity requirements, developers will likely need to install baffles or bulkheads to block off unneeded volumes of the mine. Figure 4-23 shows a conceptual sketch of an underground mine and baffles (in blue) that an operator might install to operate a high-pressure (deep) CAES facility that matches the energy storage capacity (volume) and power capacity (air duct/well diameter) with the needs of the project. Baffles can be moved, allowing the CAES volume to expand or contract as needed for storage changes over time. This flexibility in the depth and volume of the storage facility afforded by the ability to isolate different parts of a deep mine offers a huge advantage over fixed volume solution-mined salt caverns such as those used at Huntorf and McIntosh.

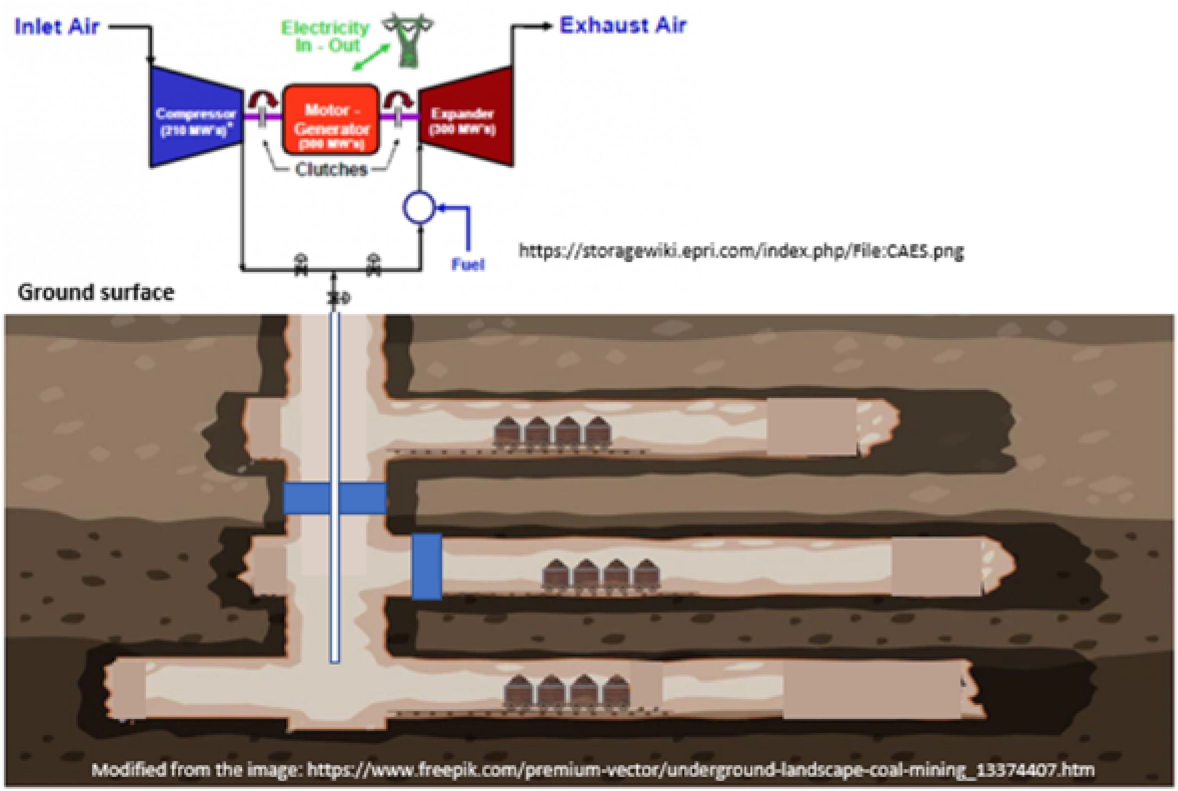


Figure 4-23. Cross section of generic abandoned coal mine with aboveground CAES infrastructure shown schematically. The belowground part shows baffles (blue) installed to restrict airflow and isolate various levels of the mine and seal off the deepest workings for CAES. The brown pointed objects depict railcars full of coal. A large-diameter vertical air duct is depicted connecting the surface motor-generator infrastructure with the storage volume.

4.6.2 Prior Experience from Cavern Systems

Two cavern CAES facilities have been in commercial operation for more than 40 years. These are the Huntorf and the McIntosh CAES plants, which both use solution-mined salt caverns as their storage vessels. The two plants store and deliver grid-scale electricity on a daily cycle. Table 4-2 contains selected technical data from the two plants. The volumes of the caverns are 3.1×10^5 m^3 for Huntorf, and 5.38×10^5 m^3 for McIntosh. Using technology from the late 1970s, both plants use NG to heat the expanding air in the turbine on the energy recovery (electricity generation) cycle. Therefore, the power output shown in Table 4-2 represents power generated both from the stored compressed air and the combusted added NG.

Table 4-2. CAES performance data at the two commercially-operated salt cavern CAES facilities (Budt et al. 2016)

Technical data	CAES plant in Huntorf, Germany	CAES plant in McIntosh, Alabama, USA
Cavern volume	310,000 m^3	538,000 m^3
Cavern pressure range	46–72 bar	46–75 bar
Cycle efficiency	0.42	0.54
Max. output power	321 MW	110 MW
Energy content	642 MWh	2,640 MWh
Max. air mass flow rate (compression)	108 kg/s	Approximately 90 kg/s
Max. air mass flow rate (expansion)	455 kg/s	154 kg/s
High-pressure turbine inlet	41.3 bar, 490°C	42 bar, 538°C
Low-pressure turbine inlet	12.8 bar, 945°C	15 bar, 871°C

To estimate the energy storage and power capacity potential of a mine CAES system, existing cavern CAES systems should be examined as analogues. Specifically, the data in Table 4-2 suggest that Huntorf and McIntosh have an average energy storage density of 2.1 and 4.9 kWh/m^3, respectively, and they both deliver power at over 100 MW for multiple hours. A hypothetical equivalent mine CAES system may be considered by sectioning off a volume of a large mine using bulkheads. Assuming 4 m diameter tunnels and shafts in the mine, the mine CAES system would require 25 and 43 km (approximately 15 and 27 mi) of tunnels and shafts to match the volumes of the Huntorf and McIntosh caverns, respectively. With multiple levels of workings typical of most underground mines, this total tunnel length and more, along with additional volume associated with resource extraction, is readily available.

In addition to the two general energy storage factors discussed—available storage volume for energy storage, and air mass flow rate for power capacity—a third factor affects CAES system capacity and efficiency. This third factor is how the technology is implemented with respect to energy recovery from the compressed air. For the two diabatic CAES systems currently in operation, heat generated during the compression process is lost. Upon expanding the compressed air in a turbine for generating electricity, expansion-related cooling would occur so severely that the turbine blades may not spin. To counter this strong cooling effect, NG (energy) is combusted in the turbine to add heat that allows the gas turbine to generate electricity. (The compressed air fed into the turbine does not need as much compression in the turbine as ambient air would need, hence the recovery of energy via CAES.) Significant R&D efforts are underway to eliminate the use of NG and implement CAES as A-CAES or potentially replacing NG in diabatic CAES with a clean energy resource (e.g., geothermal, green H_2). In A-CAES, the heat of compression is stored in a thermal energy storage unit (e.g., packed gravel) and recovered upon air withdrawal to heat the air during expansion in the turbine. As a result, the efficiency of such a system is higher.

Menéndez et al. (2019) provided simulated energy and power generation capacity results for a conventional diabatic CAES system. For the systems they modeled, they found that for a CAES reservoir volume of 1.5×10^5 m^3 (one-half the volume of the Huntorf system), approximately 500 MWh of electrical energy can be recovered per cycle (e.g., 6 h) at a power level of approximately 80 MW. Bartela et al. (2022) evaluated an adiabatic configuration for a mine shaft in an abandoned mine with a volume of about 60,000 m^3. The proposed energy storage capacity was estimated to be 140 MWh at a moderate operating pressure of 5 MPa.

R&D should be aimed at further developing A-CAES technologies that use stored or clean thermal energy for the recovery cycle to remove the need for NG. Deep underground mines and associated rock and water mass offer promising opportunities for thermal energy storage related to mine CAES.

4.7 KNOWLEDGE GAPS

While significant volume of information is available on the fundamental and modeling aspects of the reviewed technologies, there are still persistent knowledge gaps related to the assessment of their potential. The knowledge gaps relate to existing data sources and certain steps in project development. While all technologies have at least some approaches to modeling the technical potential, often the necessary inputs for the modeling process are not available.

The two major groups of factors affecting information inputs are natural and societal. The natural factors are those related to the implementation of technology. For instance, to assess the megawatt hour production from a CAES system, it requires information about the shaft mine. The information could include depth, rock density, the volume of the shaft and other excavated areas of the mine. Such information is currently not available from any known database in a comprehensive form. The societal factors include a variety of factors that relate to social acceptance of the project, the perceived risks, and benefits, including the expected rate of return. For instance, advanced nuclear the technology has been developed relatively recently. The evidence of whether the local communities will oppose a project is limited which makes it impossible to predict how long it will take to gain social acceptance. The cost of capital for the project may also be difficult to estimate, due to a small number of benchmark projects that got funded earlier.

At this point, only PV has been researched sufficiently to enable quick and close approximation of the technical and economic potential. Surface pumped hydropower has the potential to become a technology with easily estimated main technical characteristics, such as reservoir volume or length of the penstock. At this point, it is not possible to say that any subsurface technologies could be quickly developed to a level when data for them would be widely available.

5. CONCEPTUAL SITE MODELS

If a legacy mine site is available for potential clean energy project development, then based on its basic characteristics, developers could decide if surface applications or subsurface applications should be evaluated for potential deployment. LevelTenEnergy (2021) has proposed a six-pillars approach for project evaluations: (1) land and site control, (2) interconnection, (3) permitting, (4) design and engineering, (5) PPA, and (6) project finance. Built on this approach, seven pillars (adding energy justice) are proposed in this section to be considered for a project development. The evaluation Is done in stages, beginning with estimating technical potential, then economic potential, and ending with market potential. The technical potential is defined as what is technically possible without consideration of cost or practical feasibility. The economic potential is the portion of the technical potential that is economically viable but requires additional policies to break down market barriers. The market potential is the portion of the economic potential that could be achieved given current costs, policies, and technical constraints. Additionally, developers need to consider if other opportunities exist, including site-specific conditions, new technologies, and hybrid technologies. Figure 5-1 is a flowchart showing the process of such evaluation. In the following sections, examples of workflows are given for geothermal technology, solar, and PSH.

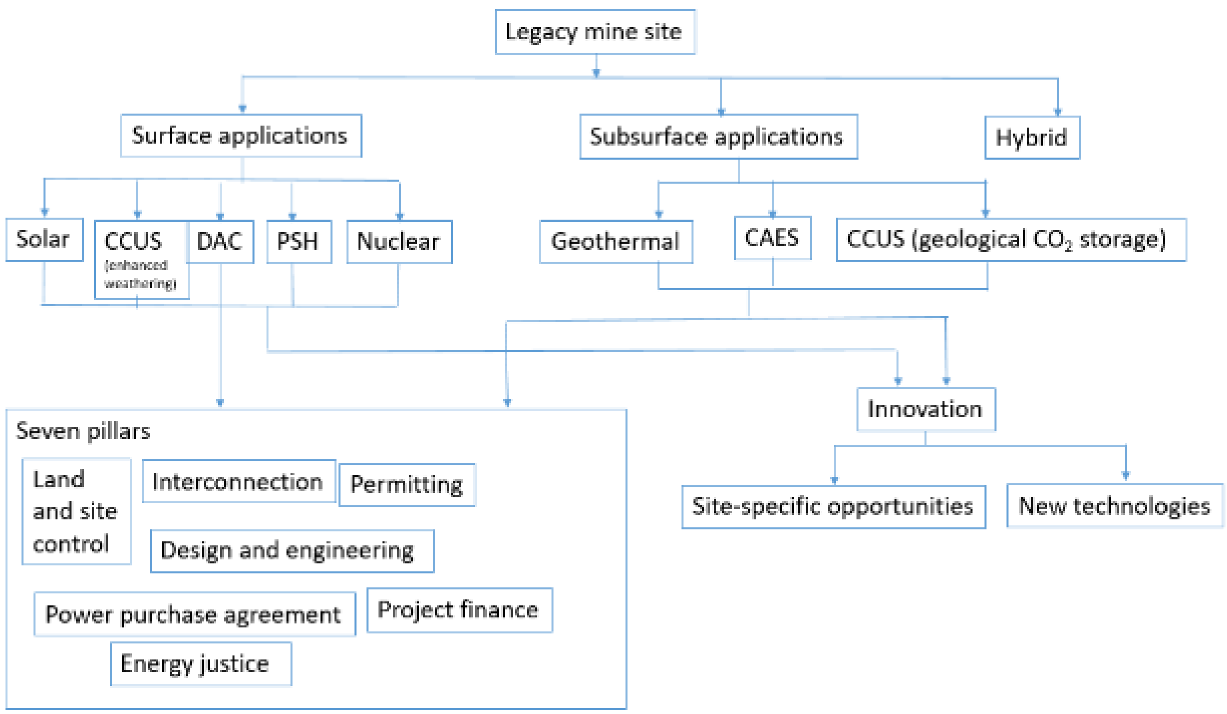


Figure 5-1. Flowchart for evaluation of a legacy mine site for potential clean energy deployment.

5.1 GEOTHERMAL

Two types of geothermal applications are illustrated in this section: high-temperature geothermal and direct-use geothermal.

5.1.1 High-Temperature Geothermal Application

In some locations, developing a high-temperature geothermal resource collocated with an epithermal mineral deposit may be feasible. A commercial-scale geothermal power development project is located at the Lihir Au deposit in Papua New Guinea (Simmons and Brown 2006, Maennling and Toledano 2018). Within the Basin and Range Province in the western United States, a number of studies have noted the presence of active geothermal systems near epithermal ore deposits (Figure 5-2) (e.g., Faulds et al. 2005, Coolbaugh et al. 2005, 2011, Simmons and Allis 2015). One of these deposits that is currently being mined, the Florida Canyon Au mine, had exploration boreholes that encountered hot water. Although this mine is an open pit Au mine (Carter 1997), elevated subsurface temperatures discovered by drilling led to the use of geothermal fluids from a borehole (223°F at 160 gpm flow rate) to power a small organic Rankine cycle unit (Clark 2014). To develop a similar type of project on mine land, it would be important to obtain the following characteristics:

- Temperature and depth of the high-temperature resource
- Productivity of the geothermal wells (resource permeability)
- Resource extent (areal extent and thickness of the geothermal reservoir)
- Geochemistry of the geothermal fluids (identify any potential issues with corrosion and/or scaling)

The technical and economic potential for geothermal power generation can be assessed based on these characteristics. It would also be important to evaluate any potential conflicts between mining and geothermal operations. Similar to direct-use applications, all of the other project development steps would also need to be addressed when evaluating the potential for a successful geothermal power project.

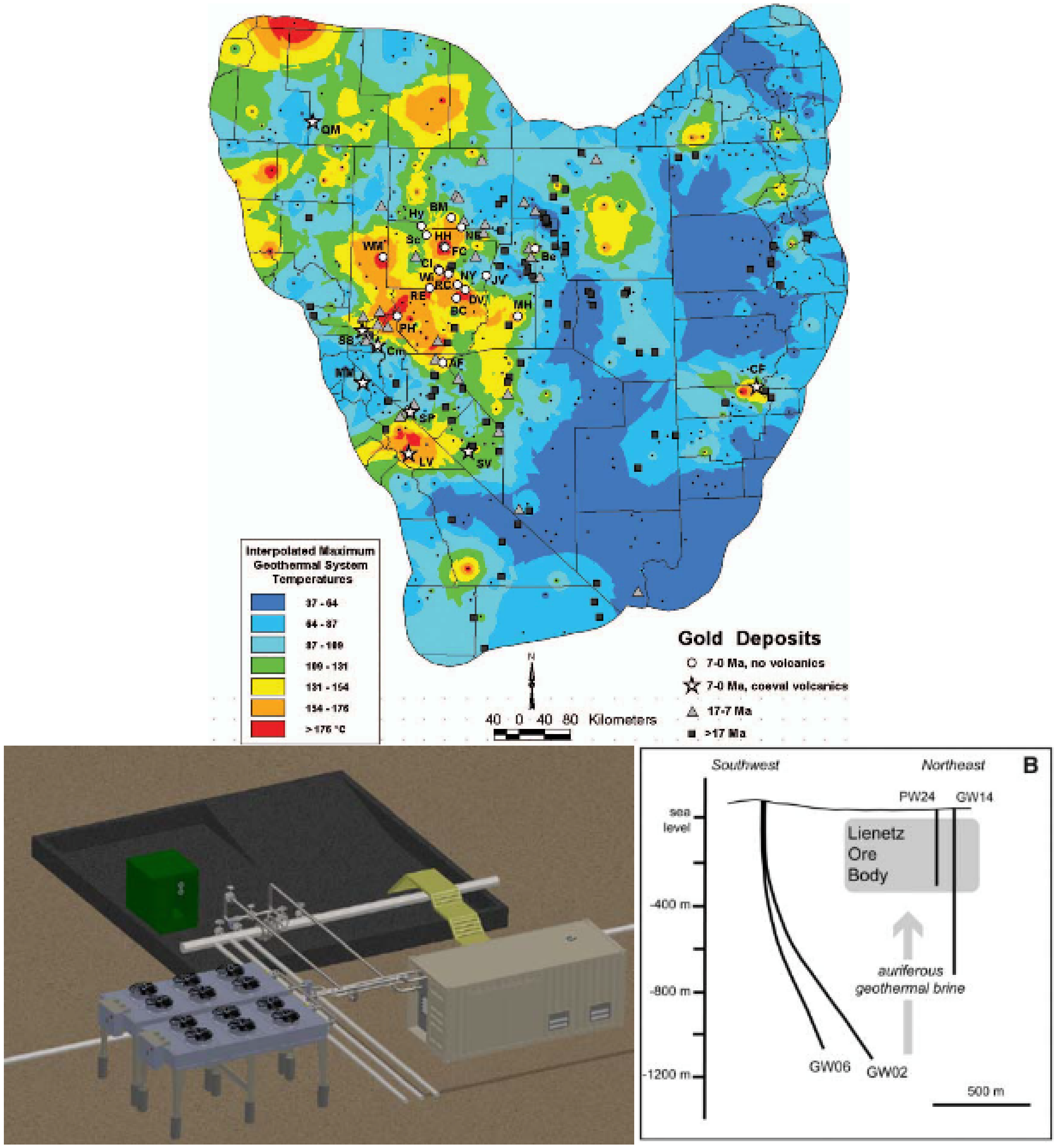


Figure 5-2. (top) Location of Au deposits and geothermal areas within the Great Basin region of the western United States (Coolbaugh et al. 2011). Warmer colors indicate areas with higher prospective geothermal resource temperatures. Gold deposits are identified by two-letter abbreviations (defined in Coolbaugh et al. 2011). Note: FC is Florida Canyon. (bottom left) Schematic representation of pilot 65 kW organic Rankine cycle unit installed at Florida Canyon, with (lower right) power plant, (lower left) air cooling unit, and (center) pipelines connecting to the geothermal well. (bottom right) Cross section depicting geothermal wells associated with the Lienetz Au ore body at Lihir, Papua New Guinea (Simmons and Brown 2006). The three deep geothermal wells all encountered temperatures in excess of 250°C. Currently, 56 MW of electricity is produced by this system (Maennling and Toledano 2018).

5.1.2 Direct-Use Geothermal Application

In this section, the process of selecting a direct-use geothermal project is illustrated in more details. Figure 5-3 shows some of the physical elements that need to be included in a closed-loop geothermal project at a site.

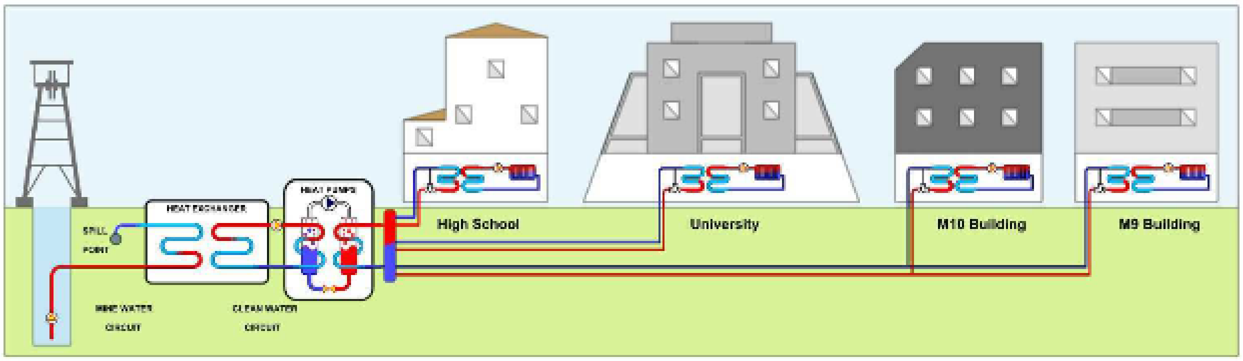


Figure 5-3. Schematic depiction of Barredo district heating system, Spain. This is a closed-loop MWG system that provides heat and cooling to multiple buildings. The closed-loop system was designed to avoid problems with poor water quality (credit: HUNOSA 2019).

The main physical elements included in a closed-loop geothermal system include the following:

1. A subsurface mine site serves as a reservoir for cold and hot water, for which the volume, temperature, water quality, and mine hydrology need to be characterized.

2. Engineering designs needed for a closed-loop, direct-use geothermal system include a heat exchanger and heat pumps.

3. End users of the energy are needed. In this case, end users are buildings with heating and cooling needs.

4. Other infrastructure, such as pipes for circulating water, is necessary for the system.

Figure 5-4 is a summary of the factors to be considered for a detailed evaluation of a direct-use geothermal project.

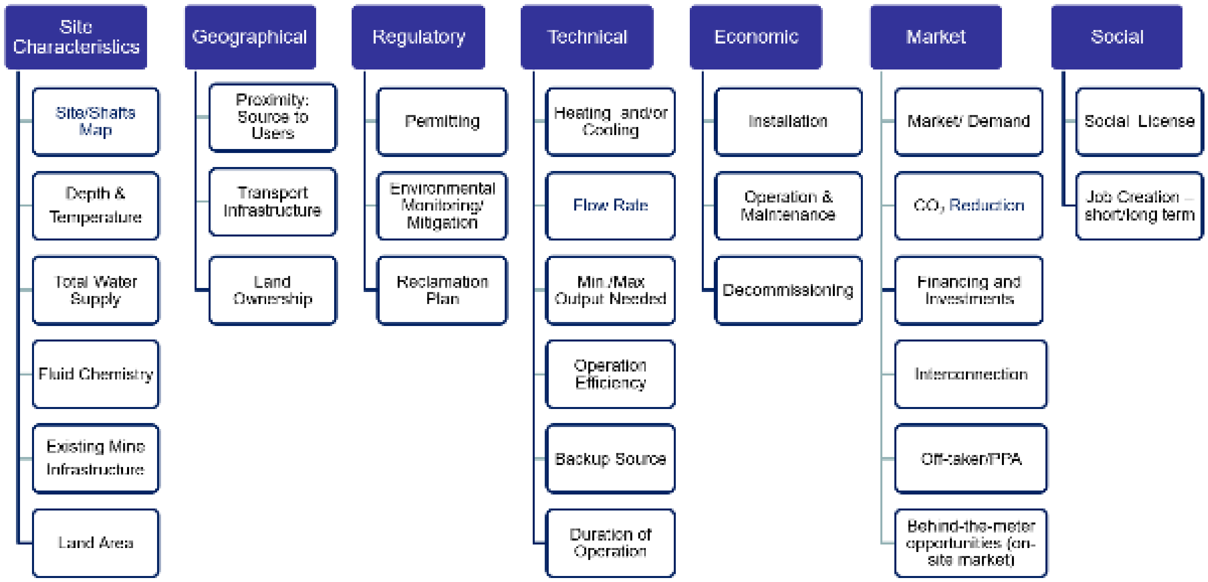


Figure 5-4. Information needed to evaluate MWG feasibility for direct heating or cooling of nearby commercial, industrial, and residential buildings, greenhouse complexes, or data centers.

Site characteristics

Knowledge of the following parameters is important when evaluating the technical potential of a site: the location and proximity to a community; minerals mined; volume of minerals excavated; host rock type; the site's maximum depth; depth to the underground workings of the site; the site's operating period; the date when it was abandoned; the volume and geometry of underground workings; the known surface communication features, such as shafts, temperature, water chemistry, hydraulic potential, geothermal potential, mine blueprints or other information, and the current use of land.

The deposit's geological structure defines the rocks' thermal properties. In addition to temperature, geothermal gradient, and heat flux, the position of the mine in the regional groundwater cycle affects the geothermal energy of mine water. A sufficient and reliable source of water near the site is important to maximize the site's efficiency. The usable geothermal potential of the mine water depends on the method of pumping, treatment, and discharge. Water chemistry assessment should be performed to optimally configure the system, anticipate the risks of scaling and corrosion, and assess the potential environmental risks to other water aquifers.

Extensive amounts of data related to geothermal resource characterization throughout the United States can be found in the Geothermal Data Repository (e.g., Weers et al. 2022).[42] Additional data may also be found in the published literature, as well as in state and USGS reports and data archives. A geothermal resource map with identified hydrothermal sites and favorability for an EGS[40] could be used as a general guide for understanding high-temperature geothermal resources. However, a higher temperature resource likely may lie beneath an existing mine, and deep geothermal wells need to be drilled to access this type of resource. In that case, more typical geothermal resource estimate methodologies could be applied to assess the generation potential of such a resource (e.g., Cumming 2016).

The steps to evaluate the geothermal resource potential for direct-use applications (including both heating and cooling) are similar to geothermal power generation applications. The available thermal energy is estimated using the volume of water in the mine, the temperature of the mine water, and the change in temperature that determines the amount of thermal energy that can be extracted from the flooded mine. The effects of thermal recharge from surface infiltration and groundwater flow should also considered.

Geographical

The distance between the source and the community or end user for district heating and rights-of-way influence the cost and viability of the application. The mine can have moderate to significant potential when this distance is short. The prospect of developing a successful direct-use project is unlikely for remote or very small mines. Existing rights-of-way need to be reviewed, and developers need to determine if existing pipelines are suitable or if they need a retrofit.

Other factors to consider are local climate, the distance from and access to power distribution and transmission networks, the price of purchasing and transporting alternate energy sources, the size and type of the geothermal resource in terms of production enthalpy, achievable mass flow rates, and brine mineral content (e.g., Díaz-Noriega et al. 2020, Younger and Loredo 2008). Farr and Busby (2021) identified that site ownership and water rights, which may be difficult to define for current and former mine land and geothermal, are possible barriers to new development.

Regulatory and permitting framework

The regulatory and permitting framework is complex for geothermal resource use on mine land, and the framework varies depending on the location of the project, the land ownership, and the type of geothermal project that is envisioned. Section 3 provides a brief summary of steps to follow to meet existing regulations and permitting requirements governing the use of geothermal resources. Notably, these vary by state and site conditions and can change with time. Additional regulatory and permitting requirements might be required owing to the location of a project on active, reclaimed, or abandoned mine land.

The most evolved set of regulations for geothermal resource development applies to high-temperature geothermal resources for power generation. BLM typically oversees the permitting and regulation of geothermal power projects on federal land. Because tribal entities have sovereignty over tribal territory, approval from tribal governments is required for any geothermal projects that will be located on tribal lands. Numerous state, regional, and local agencies also are involved in these regulatory and permitting efforts.

The permitting and regulatory framework for geothermal exploration and development activities on state and private lands varies from state to state. In some states, geothermal resources are considered a water resource, and in others, they are considered a mineral resource. Therefore, the state agencies governing the regulation and permitting of geothermal resources may vary. In some states, the county where the project is located also has a role in permitting and regulatory issues. NREL developed a toolkit, the Regulatory and Permitting Information Desktop (RAPID) Toolkit,[30] containing a detailed summary of these different regulatory frameworks for 12 western states. A NEPA database contains the required environmental analysis for geothermal projects.

The regulatory and permitting framework for GHPs, which are also known as GSHPs, varies state by state, and the framework may also be subject to local requirements within a state. Three main types of GHP systems exist: (1) closed-loop horizontal systems, (2) closed-loop vertical systems, and (3) open-loop systems. A report by the EPA (1997) summarizes how each state regulates these systems. Horizontal closed-loop systems that do not require drilling have the fewest permitting requirements. For vertical closed-loop systems, permitting requirements are similar to those of water well drilling, but they have additional requirements if chemical additives are contained within the closed-loop network. Open-loop systems may interact with the local aquifers. Thus, these wells typically fall under the guidelines of the federal Underground Injection Control program, which regulates the injection of fluids into the subsurface. The design and installation of these systems are expected to follow the best practices guidelines of the International Ground Source Heat Pump Association (IGSHPA 2017).

Technical (design and engineering)

The design of the system depends on the resource size and the end user needs. A direct heating application typically consists of three parts: (1) a primary circuit with a pump and mine water accumulated in a retention tank on mine land, (2) a secondary circuit that transports heat to the boiler plant heat pumps, and (3) end user infrastructure (individual heat pumps or central district heating system). The boiler plant also has metering and control units. Alternative options include the retention tank in the secondary circuit or different backup options (e.g., gas boiler in the boiler plant or bivalent heat pumps at the buildings). In some cases, decontamination stations are also necessary. Table 3-1 lists the parameters needed to evaluate the technical feasibility of a system.

A higher mine water temperature means the delivered temperature and the coefficient of performance are higher, as well. Although open-loop systems are more common and simpler than closed-loop systems, the closed-loop configuration is used for mines with contamination issues or insufficient water volume. The advantages of the open-loop system are better thermal exchange efficiency; systems with recharge are more sustainable and are suitable for small- or large-scale end users. The disadvantages of open-loop are that maintenance costs are higher than closed-loop, mines with water contamination issues need a so-called *clean water loop*, and water treatment and water depletion need to be considered if there is no reinjection. The closed-loop system advantages are that maintenance costs are lower than open-loop, fewer adverse environmental effects occur, and the system is suitable for a small volume of mine water and for contaminated mine water. The disadvantages of this system are that the heat transfer performance is lower, and the closed-loop system may be appropriate only for small-scale end users.

Economic

The project economics depend on various factors (e.g., the prevailing energy market prices and the LCOE). Several tools are available to estimate the costs and LCOE of a geothermal power generation project (such as GETEM) (Mines 2016) or to estimate the financial viability of geothermal projects (such as MAGE), Goodman et al. 2022). These tools also make it possible to compare geothermal with other clean energy development options. Wall et al. (2017) noted that project risk greatly affects the cost of capital needed to finance a project, thus affecting the weighted average cost of capital of the project.

Geothermal power generation projects have several defined steps, each with different costs and project risks. The predrilling exploration phase typically carries a high risk and relatively low costs. Exploration drilling to confirm the presence of a geothermal resource has elevated costs and a relatively high risk. If a project is economically viable and financing is obtained, drilling production and injection wells and constructing the power plant and pipelines leads to plant start-up and operations. This latter phase of a project carries a low risk.

Project risk is also important to consider for a direct-use geothermal development on mine land. Insufficient information about abandoned subsurface mines can result in a high upfront risk that translates into high capital costs (e.g., drilling wells to delineate the resource). To lower overall project costs, developers can use engineered features associated with mine sites where the capital and operational costs are already committed or capitalize on the existence and possible use of the existing central district heating boiler plant and distribution network. In some cases, retrofitting existing infrastructure or backup equipment for energy recovery are additional costs that can be considered.

For GHP systems, the following items need to be estimated: installation, O&M, and decommissioning costs and the costs of contingency plans, along with other factors such as advances in heat pump technology, GHG reduction, ongoing water treatment costs, or competition from cheaper alternative energy sources.

When a geothermal operation is constructed on mine land that is still being reclaimed, the mining operator would need to fully transfer liability to the geothermal developer during the course of the mine's reclamation. Then, the geothermal developer would need to demonstrate knowledge and capabilities to complete the site reclamation successfully. One option would be to integrate the heat exchange process as part of any required water treatment operation for a mine. The economic analysis needs to include any required site reclamation costs associated with this process.

Market

Factors to be addressed in a market analysis include the following:

- Heating/cooling demand vs. supply, and how these may change in the future
- Key energy sectors and customers: for example, is heat used in mineral processing? Or, controlling working conditions on-site (e.g., ventilation, space heating, or cooling) or nearby district heating/cooling.
- Are any other energy-saving alternatives possible?
- Decision makers: who are they, and what are their main considerations? Do they need assistance?
- How to factor in energy reliability, peak-use switch, and reduction in CO_2 emissions
- Cost development and financial risk at various stages of the project
- Potential for behind-the-meter power use (internal use at the mine)
- Interconnection to the grid
- Off-taker/PPA

Social considerations

Stakeholder outreach is a key component of any geothermal development project, whether it is a high-temperature power generation project or a low-temperature district heating system. For social acceptance of a project, which is critical, the project developers must be in regular contact with the local communities, regulatory and permitting groups, and other interested parties from the outset of the project.

Community drivers for using geothermal can include a desire to continue using mining operations infrastructure in a community that has important historical, heritage, and cultural ties to mining. Other drivers are the community's remoteness, allowing it to generate energy locally without supply chain hurdles. Other drivers may be job creation, lower operational costs, and a desire to develop low-carbon energy sources (Chu et al. 2021).

5.2 SOLAR

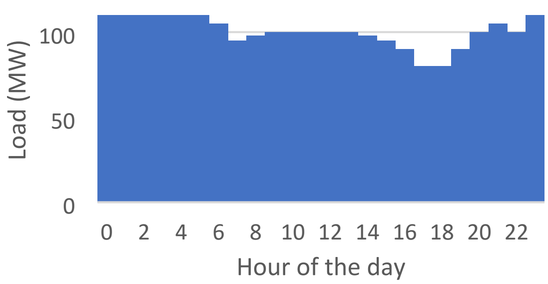
5.2.1 Use of Solar in Microgrids or Connected Systems

PV facilities can be co-located with on-site battery storage. A combination of PV and battery storage is a well-researched application and is briefly reviewed here, using the Sun Metals Zn refinery in Queensland, Australia (Ekistica 2018), as an example. The Sun Metals Zn refinery has a 124 MW AC PV system and a load that varies between 80 and 110 MW. Figure 5-5 shows a marble quarry located at (32.232140, −109.511680) in Arizona, near the border with Mexico. The quarry currently produces marble and can accommodate a 124 MW PV system.

Figure 5-5. The White Marble Quarry.

The location and climate of the quarry enables obtaining estimates of its solar output and comparing them with that of the Sun Metals Zn refinery. The actual load profile of the quarry is not known, and it was assumed to be similar to the Sun Metals load, as shown in Figure 5-6(a), and the output profile of a model PV array was assumed as shown in Figure 5-6(b).

a)



b)

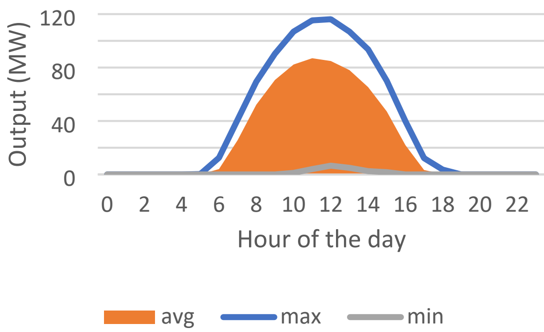


Figure 5-6. (a) Example load profile, (b) Hourly output profile of a model PV array.

Here, pvlib, a Python package developed by Sandia National Laboratories based on System Advisory Model, was used to simulate a PV array that produces 124 MW of output in clear sky conditions. The model was applied to 1 year of hourly weather estimates from NREL's National Solar Radiation Database (NSRDB), using 2020 as a reference year. Because of a variation of irradiance, the megawatt output of the 124 MW array would vary, and the range of output is provided in Figure 5-6 (b).

The average output per year is between 40 and 90 MW per hour between 8 a.m. and 3 p.m., which are the hours with highest production. The system is therefore sized to be on average below the 90–100 MW load for the mining and processing operations described in Figure 5-6 (a). The peak PV production, however, is higher than the load for some of the hours. The distribution of the number of days in which PV production exceeds 100 MW is shown in Figure 5-7.

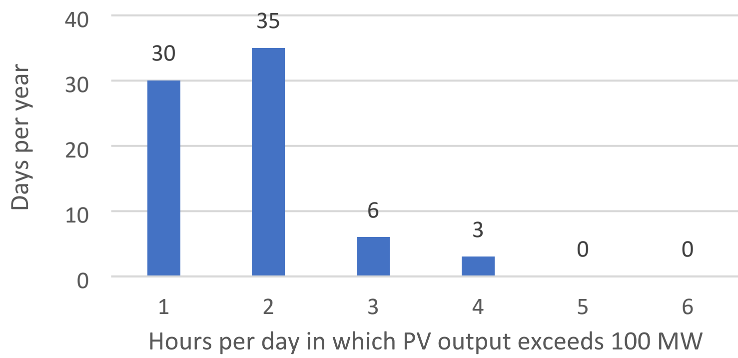


Figure 5-7. Distribution of the number of days in which PV production exceeds 100 MW.

There are 74 days in the model when the PV output exceeded 100 MW. Importantly, the duration of the output in excess of 100 MW was usually 1 or 2 h straight. There were only 6 days in which PV output exceeded 100 MW for 3 h, and 3 days in which PV output above 100 MW was observed for 4 h per day. A battery system of 10–15 MWh would be sufficient to store all the excess solar production for such a PV array and would be used about 74 times per year. The batteries for the system would cost around $2 million, according to a recent study by Lawrence Berkeley National Laboratory.[43]

5.2.2 Specific Use Cases for Photovoltaic Battery Microgrids

The relative size of the energy storage system will depend on the primary use cases being targeting by the site. If full off-grid operation is desired, then a very large battery plus PV installation is necessary. Demand reduction may require a high-power, low-energy battery to operate for only 2 h per day. PV smoothing may require a very small battery in terms of both power and energy, but it also has the smallest economic impact. Within each use case, undersizing of energy storage can result in ineffective operation, and oversizing can result in higher costs. Therefore, energy managers must understand and prioritize use cases to effectively size an energy storage system.

5.2.2.1 Constant load

Consider a hypothetical off-grid mine operating at 10 MW of load with a photovoltaic solar + energy storage installation. Because the mine is off-grid, the instantaneous load and generation must be equal at all times, and the site must produce at least as much energy as it consumes. Let's assume the mine is located in an area with 5 peak sun hours daily, such as the southwestern region of the United States, as shown in Figure 5-8. Peak sun hours represent the number of hours that the solar array produces its

[43] https://international.lbl.gov/publications/estimating-cost-grid-scale-lithium#:~:text=Our%20bottom%2Dup%20estimates%20of,and%20%2492%2FkWh%20in%202030

maximum power. There will still be a few hours before and after peak sun when the array produces power, but it will not be at peak power level.

Assuming continuous operation around the clock, the mine would consume 240 MWh of energy each day. If the solar array were sized to meet the energy needs of the mine for a 24-hour period plus a 10% margin (chosen arbitrarily), using an ideal solar generation curve (5 peak hours, no cloud cover), the array would need to be ~ 30 MW. Assuming that it takes between 5-10 acres of land to produce 1 MW of solar power, the solar installation would need between 150 and 300 acres of land to produce enough energy to support the microgrid.

During peak solar hours, the array would generate 30 MW while the load would be 10 MW, resulting in 20 MW of solar needing to be stored in a battery or other energy storage device. In total, roughly 140 MWh of storage would be needed to capture enough excess solar generation to last throughout the night, ignoring efficiencies. PV curtailment may be needed to maintain system stability when the energy storage system is near 100% state of charge (SOC).

The microgrid design must also consider prolonged cloudy weather, which would add to already steep capital costs. Note that this example considers only PV + storage; other generation technologies could be used to reduce the energy storage requirement.

Table 5-1. Load, PV production, energy storage output, and SOC for constant load

HOUR	LOAD (MW)	SOLAR PRODUCTION (MW)	ENERGY STORAGE OUTPUT (MW)	SOC
0	10	0.0	10.0	41%
1	10	0.0	10.0	33%
2	10	0.0	10.0	26%
3	10	0.0	10.0	19%
4	10	0.0	10.0	12%
5	10	0.0	10.0	5%
6	10	4.8	5.2	1%
7	10	14.0	-4.0	4%
8	10	22.9	-12.9	13%
9	10	30.0	-20.0	27%
10	10	30.0	-20.0	42%
11	10	30.0	-20.0	56%
12	10	30.0	-20.0	70%
13	10	30.0	-20.0	85%
14	10	24.4	-14.4	95%
15	10	13.5	-3.5	97%
16	10	6.5	3.5	97%
17	10	0.3	9.7	91%
18	10	0.0	10.0	83%
19	10	0.0	10.0	76%
20	10	0.0	10.0	69%
21	10	0.0	10.0	62%
22	10	0.0	10.0	55%
23	10	0.0	10.0	48%

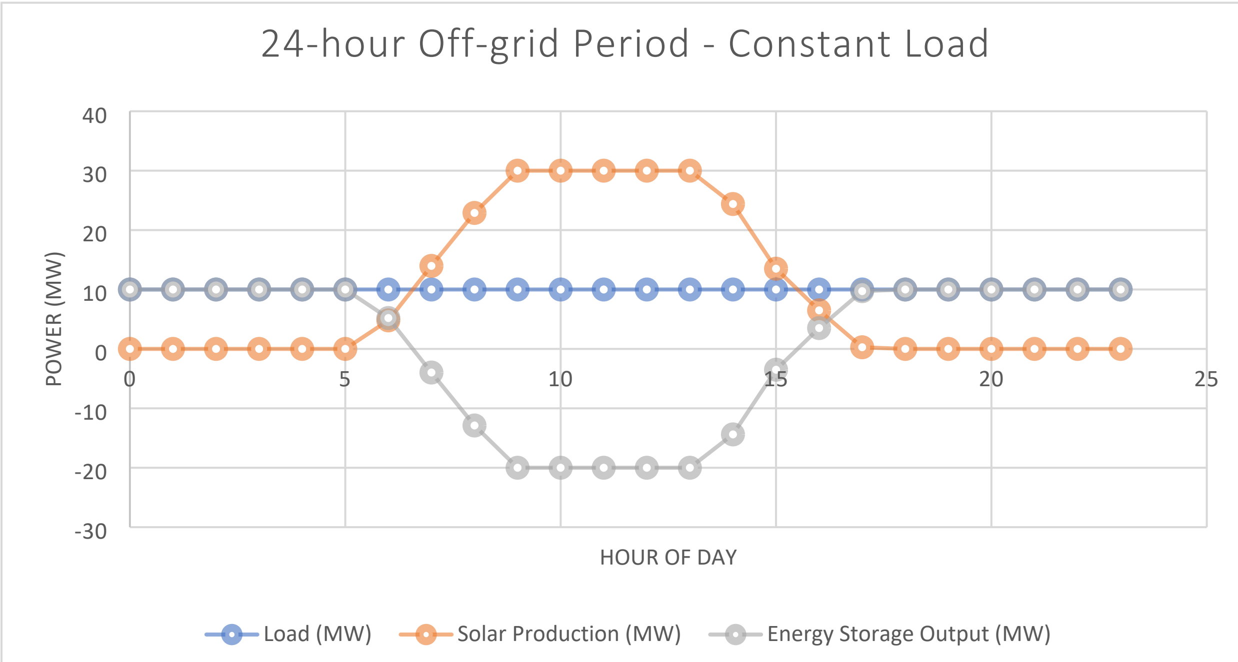


Figure 5-8 Constant load PV production and energy storage output.

5.2.2.2 Varying load

Consider the same hypothetical mine as example 1, but now operating with multiple 2 MW loads, totaling 26 MW with a solar + storage installations, as described in Figure 5-9. The loads are spun up in accordance with solar production, with the total daily energy consumption being 240 MWh, the same as example 1.

In this case, where loads can be turned on in small steps following solar production, the PV array size is kept the same, but the energy storage capacity can be reduced from 140 MWh to 27 MWh. While not all operations may be able to support this level of flexibility, this case shows that utilizing load flexibility when off-grid can greatly reduce energy storage size, which is a major component of the microgrid cost.

Actual microgrids will likely fall somewhere in between these two cases in terms of load flexibility, but a key takeaway is that by better aligning mine operations with the types of generation can result in capital cost savings and increased efficiencies.

Table 5-2. Load, PV production, energy storage output, and SOC for varying load

HOUR	LOAD (MW)	SOLAR PRODUCTION (MW)	ENERGY STORAGE OUTPUT (MW)	SOC
0	2	0.0	2.0	42%
1	2	0.0	2.0	34%
2	2	0.0	2.0	27%
3	2	0.0	2.0	20%
4	2	0.0	2.0	12%
5	2	0.0	2.0	5%

6	4	4.8	-0.8	8%
7	14	14.0	0.0	8%
8	22	22.9	-0.9	11%
9	26	30.0	-4.0	26%
10	26	30.0	-4.0	41%
11	26	30.0	-4.0	55%
12	26	30.0	-4.0	70%
13	26	30.0	-4.0	85%
14	24	24.4	-0.4	86%
15	14	15.8	-1.8	93%
16	6	6.5	-0.5	100%
17	2	0.3	1.7	94%
18	2	0.0	2.0	86%
19	2	0.0	2.0	79%
20	2	0.0	2.0	71%
21	2	0.0	2.0	64%
22	2	0.0	2.0	57%
23	2	0.0	2.0	49%

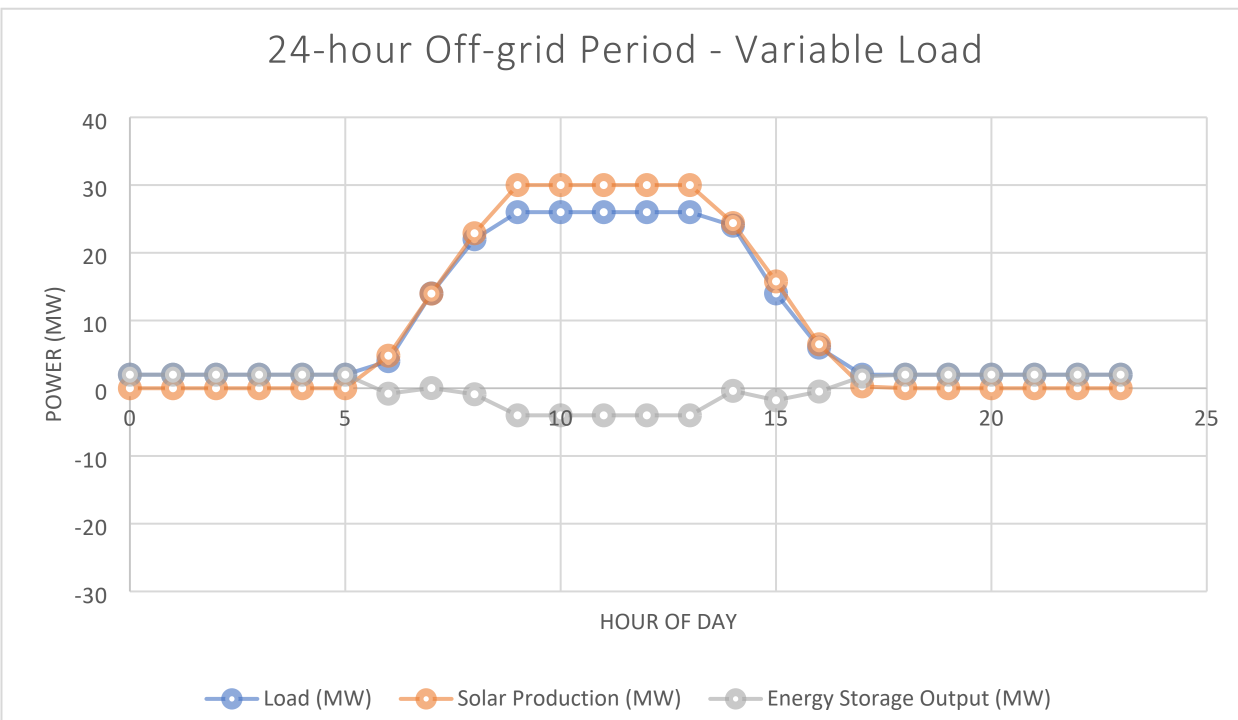


Figure 5-9. Varying load PV production and energy storage output

5.2.2.3 Photovoltaic smoothing

Using a site controller, an operator can set a target curve for the PV plus energy storage system to follow and output throughout the day. Whenever the measured PV power output dips below or exceeds a specified threshold, the storage system can kick in and provide the difference. The following analysis is providing examples of this use case on a 5 min average for a 330 kW PV array and a 700 kWh Li-ion battery. The power output of the battery forces the net output of the PV plus energy storage to follow the blue curve, which is much smoother than the nominal PV output (orange). Figure 5-10 shows that the energy storage state of charge stays between 45% and 65%, which indicates that there is excess capacity in this battery when performing this use case. A solar production survey should be done at the installation site to determine the appropriate energy content of the energy storage system. The energy storage inverter should be able to provide at least 90% of the total PV array power for full smoothing effects.

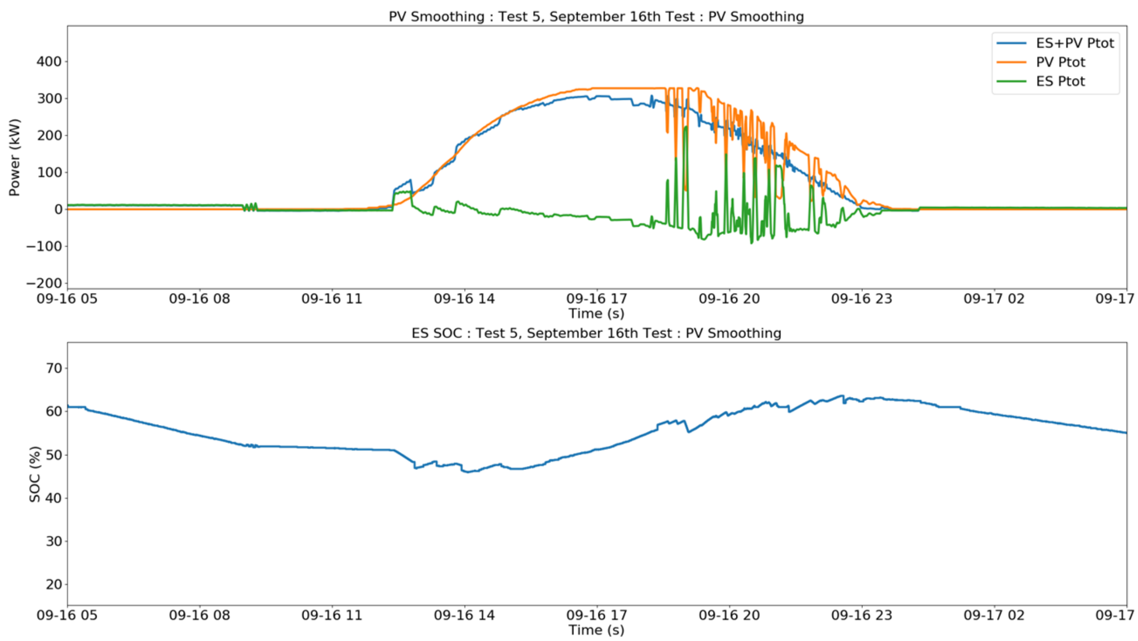


Figure 5-10. Solar smoothing use case with battery.

5.2.2.4 Microgrids

A microgrid is a collection of sources and loads which that can be isolated and run independently from the bulk electric grid. Many microgrids operate grid-tied most of the time, providing services such as reactive power compensation or peak shaving back to the utility. During a service interruption, a microgrid opens its point of interconnection to the grid, and has one of its DER go into grid-forming mode. The grid-forming device is expected to provide a solid voltage and frequency reference for the rest of the sources and loads in the network, and multiple devices can act as the grid-forming device in droop mode. Some sources, such as PV and wind, are unsuitable as grid-forming devices due to the instability of their fuel supply. Batteries, fossil generators, or fuel cells are more robust grid-forming devices.

The size of an energy storage system in this case is primarily dependent on a few factors, including: amount of critical load to be served, the desired island duration, and the number and type of sources within the microgrid. Often in islanded mode, a facility will operate only its "critical loads", or some subset of its total electrical consumption deemed critical to the operation of the site. In an outage situation, it can be unknown when service will be restored, so serving a smaller amount of critical load can extend the maximum duration of the island. That is, if an energy storage system is the grid-forming device, and no other grid-forming device is available or operable, then the island duration will be directly related to the energy capacity of the energy storage system. This duration can be bolstered with fossil generators, PV, wind, and load control. For always-islanded microgrids, managing the available energy in the microgrid is a full time commitment to ensure stable operations.

An example islanding event is shown in the figure below for a microgrid with a battery, PV array, genset, and load. The PCC represents the point of common coupling, which is the power flowing between the microgrid and the bulk grid. An unexpected outage occurs at 14:54, causing the ES to go into grid-forming mode. After a few minutes, the generator is turned on to bolster the ES and serve the load. At 16:03, the microgrid reconnects to the grid and goes back to business as usual.

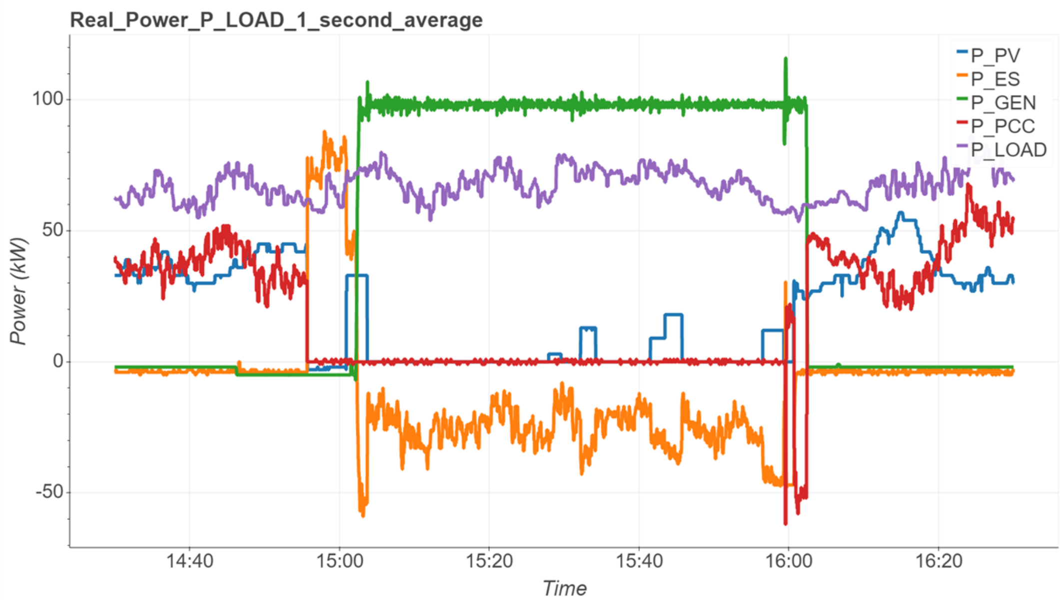


Figure 5-11. Use case for islanded operation of a microgrid and each distributed energy resource.

5.2.2.5 Blackstart

A blackstart occurs when there is a total loss of grid and site power. Certain types of DER, such as generators and batteries, can provide blackstart capabilities to re-energize a site after loss of the bulk grid. This function goes hand-in-hand with microgrids, as most microgrids and microgrid controllers will have some form of blackstart.

A blackstart sequence may be required depending on the amount of load within a site. Of primary concern will be inrush currents associated with the energization of transformers. Inrush currents can easily trip inverter-based generators if not accounted for during the blackstart sequence. Breakers, reclosers, and sectionalizers may be needed to break the system into smaller pieces to allow for a multi-step restoration process of a site. For blackstart using an energy storage system, extra attention should be given to the overcurrent capabilities of the inverter. Too much inrush current will result in tripping the overcurrent protection of the inverter and a failed blackstart.

5.2.2.6 Energy arbitrage

Energy arbitrage is the practice of buying power at low cost and selling it at high cost. Energy storage systems are excellent at this because they can store excess low-cost renewable energy for hours or days at a time, then discharge during peak demand times at a profit. The ability for an installation to perform this use case depends on local utility regulations and PPAs. For this use case, the size of the energy storage system is limited only by the available capital to invest in the system and any power flow limits on the utility's infrastructure.

Figure 5-12 shows an example of energy arbitrage, where the energy storage stores energy all morning using the output of the PV array, before discharging during peak demand times. In this case, there is a limit on how much power can be sent back to the utility from the microgrid at any point in time, which is why the output ramps up as PV power ramps down.

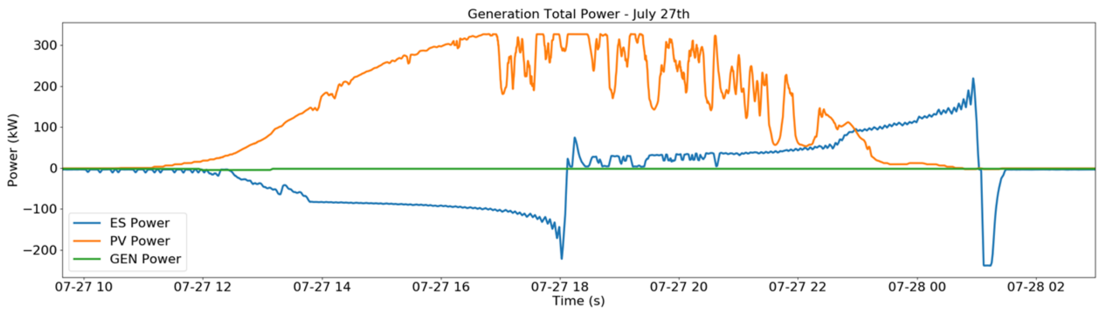


Figure 5-12. Use case for energy arbitrage.

5.2.2.7 Net-zero operations

In net-zero operations, the power exchange between a customer and the utility is not necessarily zero at all times. In practice, the net energy flow across the meter is zero over some predefined time period (e.g., daily, monthly, yearly). Often, over-generation from PV power flows back into the utility during peak production times, and local DER and load control methods are dispatched during the night to try to match the energy production from the day.

Something to note when sizing systems for net-zero operation is that any PV system not located near the equator will have a significant difference in output between summer and winter. If targeting daily net-zero operation, PV generation may need to be bolstered with another source to achieve net-zero in these months. If a site targets net-zero over an annual period, a yearly output and consumption model will be needed, and progress must be tracked throughout the year.

5.2.2.8 Market participation

Certain areas of the United States have markets for ancillary services, such as frequency regulation. If a unit is registered with the utility to provide this service, it can be called on to modulate its output in response to a signal from the local balancing authority. Compensation varies based on the area and the size of the unit committed to providing the service.

A related but distinct form of market participation is in the form of demand reduction. During times of high demand, customers and utilities may be asked to reduce their consumption to preserve the stability of the bulk grid. The local utility will often have a program that compensates customers who participate in a demand reduction program. Often, the customer will be notified 24 h in advance of a potential demand reduction event. During one of these demand reduction events, a site can provide demand reduction in the form of a discharge of energy storage without compromising operations. This discharge could be combined with load shedding or full shutdown to maximize the demand reduction and compensation from the utility.

Both forms of market participation will require the energy storage be sized to provide a certain amount of power for a set duration. The process of determining the size requires an economic study based on local programs and regulations applicable to the site.

5.2.3 Substation Infrastructure

5.2.3.1 Conventional and nonconventional protection schemes

The methods to protect PV arrays are based on conventional and nonconventional protection schemes applied in microgrid projects. Conventional protection schemes are defined as those described in the ANSI/IEEE Standard Device Numbers Standard, and nonconventional were those not included in this standard (IEEE 2008). Microgrids can be operated in grid-connected or islanded modes, and they are designed based on different protection schemes to enhance their reliability, resilience, and power quality (Hirsch, Parag, and Guerrero 2018). The protection schemes are different for the DER scenarios, such as grids connected and islanded with hydropower (large spinning inertia cases) and PV panels with energy storage systems (synthetic inertia cases). The detection of possible electrical faults could depend on the types of generator sources, including the total power of the electrical machine and its mechanical inertia at the moment of an electrical fault situation.

Understanding the impact of conventional and nonconventional protection schemes on current projects is crucial to adapt traditional or advanced protection schemes. The conventional protection schemes are defined as the protection devices described in the ANSI/IEEE Device Numbers Standard (IEEE 2008). The most common conventional protection schemes used in renewable energy source (PV arrays, hydropower generators) for North American microgrid projects were undervoltage (27), overvoltage (59), voltage balance (60), volts per hertz (24), frequency (81), impedance (21), differential (87), instantaneous overcurrent (50), inverse time overcurrent (51), and directional overcurrent (67). Table 5-3 describes the advantages and disadvantages of conventional protection schemes based on actual microgrid projects (Piesciorovsky, Smith, and Ollis 2020).

Table 5-3. Conventional protection schemes for microgrid projects (Piesciorovsky, Smith, and Ollis 2020)

Functions (device Nº)	Advantages	Disadvantages
Undervoltage (27)	• Does not depend on fault current magnitude and direction	• Does not allow a good selectivity coordination • Susceptible to transient incidents (load operations)
Overvoltage (59)	• Does not depend on fault current magnitude and direction • Protects inverters	• Does not allow a good selectivity coordination • Susceptible to transient incidents (load operations)
Voltage balance (60)	• Detects blown voltage transformer fuses to protect generators	• Does not allow selectivity coordination
Volts per hertz (24)	• Protects inverters	• Does not allow a good selectivity coordination • Susceptible to transient incidents (load operations)
Frequency (81)	• Protects inverters	• Does not allow a good selectivity coordination • Susceptible to transient incidents (load operations)
Impedance (21)	• Provides solution for islanded microgrids	• Lacks sensitivity to measure apparent impedances at fault situations with DER contributions • Needs communication
Differential (87)	• Does not depend on fault current level • Does not depend on DER type, location, or size	• Does not allow a backup protection from other zones • Needs communication
Instantaneous overcurrent (50)	• Allows an instantaneous trip but is used with the inverse time and definite time overcurrent relays	• Does not allow coordination with fuse curves • Needs to be used when coordination is not required (last relay application)
Inverse time overcurrent (51)	• Allows coordination of relays with feeder fusses	• Needs to be complemented with directional and/or adaptive overcurrent protections

		• Needs communication
Directional Overcurrent (67)	• Provides proper solution to coordinate protectives devices for different microgrid circuit paths	• Needs forward and reverse coordination • Needs adaptive settings

Alternatively, the nonconventional protection schemes are protection functions that are not set in the ANSI/IEEE Device Numbers Standard (IEEE 2008) but are applied in current microgrids. The most common nonconventional protection schemes applied in microgrids are adaptive, voltage-restrained, hierarchical, and symmetrical component protection schemes. The nonconventional protection schemes are based on traditional protection schemes but apply additional functions that protect and control the DERs, DC/AC inverters, energy storages, transformers, power lines, and feeders for different operation modes and/or circuit path applications for microgrids. Table 5-4 describes the advantages and disadvantages of nonconventional protection schemes based on current projects.

Table 5-4. Nonconventional protection schemes for microgrid projects (Piesciorovsky, Smith, and Ollis 2020)

Functions	Advantages	Disadvantages
Adaptive protection	• Allows sensitivity and selectivity based on microgrid operation conditions	• Needs communication • Needs large amount of data for real-time adaptation of protection settings • Has a complicated design
Voltage-restrained	• Enhances fault detection that could not have overcurrent relays • Detects low fault currents	• Has difficult coordination • Lacks success to detect high-impedance faults
Hierarchical	• Allows for coordinating differential protection schemes at different protection levels	• Needs communication
Symmetrical component	• Allows for detecting asymmetrical faults	• Cannot detect some types of faults • Needs to be implemented with other protection elements

Based on protection schemes used in North America (Piesciorovsky, Smith, and Ollis 2020), the conventional protection schemes applied in North American projects are shown in Figure 5-13. The power quality is represented by the voltage and frequency ranges. The overvoltage (59), undervoltage (27), and frequency (81) elements were the most common conventional protection schemes related to the power quality of the microgrids. In addition, the overvoltage (59), undervoltage (27), and frequency (81) elements were used to detect the islanding conditions. The directional overcurrent (67) elements were important in microgrid projects because they allowed external (grid) faults to be distinguished from internal (microgrid) faults. In addition, the directional overcurrent (67) elements were set in forward and reverse directions by using inverse time (51) and instantaneous (50) overcurrent curves. The nonconventional protection schemes applied in actual North American projects are shown in Figure 5-14.

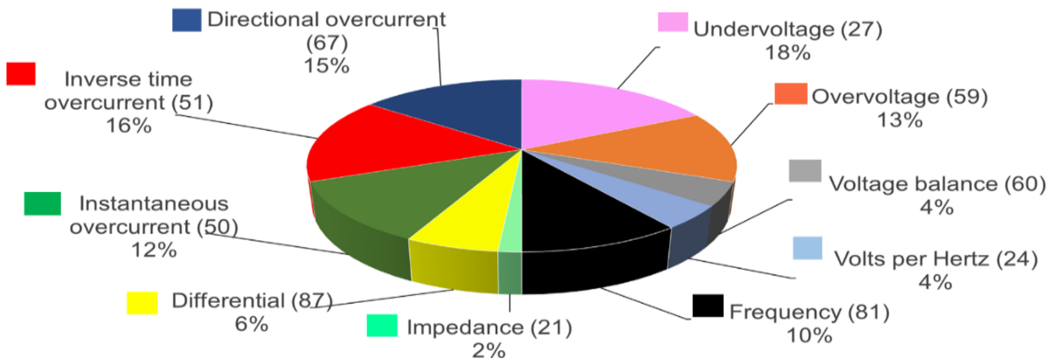


Figure 5-13. Conventional protection schemes (Piesciorovsky, Smith, and Ollis 2020).

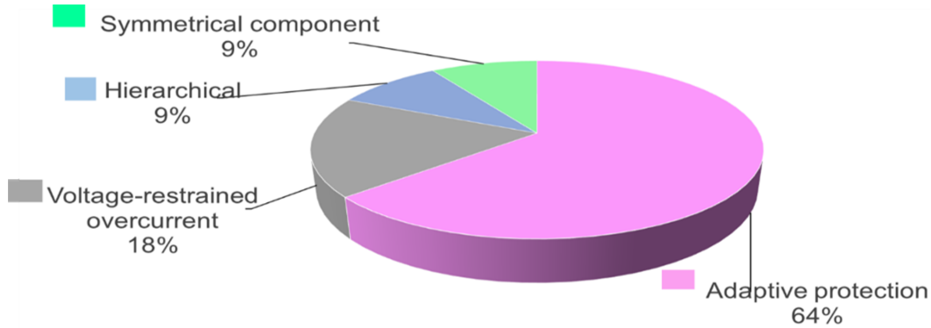


Figure 5-14. Protection schemes for microgrids (Piesciorovsky, Smith, and Ollis 2020).

The adaptive protection scheme was the most common nonconventional protection scheme applied in microgrids. The scheme could detect if the microgrid was set in grid-connected or islanded mode and select the relay settings for the actual microgrid conditions and avoid relay misoperations. The voltage-restrained overcurrent protection scheme was also used for the islanded modes of the microgrid. The scheme provided improved sensitivity of overcurrent relaying by making the set overcurrent operating value proportional to the applied input voltage. The voltage-restrained overcurrent protection improved the sensitivity of the overcurrent relays for small fault currents.

5.2.3.2 Metering and sampling frequency

PV arrays are a great promise as power generation sources to help meet the growing demand for energy (García-Gracia 2011). However, the increasing of these renewable energy sources has raised concerns by electrical utilities regarding to microgrid protection (Hooshyar and Iravani 2017) and power quality (Hong and Zuercher-Martinson 2011). These concerns have led to the need for power meters and protective relays that can measured over a range of frequency currents and voltages under normal and transient situations. IBDGs pose a major challenge to the protection and coordination of islanded microgrids. As indicated in IEEE Standard 1547 (IEEE 2009), islanded microgrids with IBDGs cannot provide sufficient fault current magnitude for the operation of conventional protective devices because of the low fault current levels injected by IBDGs, which are normally limited to 120% of the inverter rated current (Soleimanisardoo, Karegar, and Zeineldin 2019). Therefore, distribution electrical protection devices, such as fuses and overcurrent relays, cannot provide a reliable protection because of the limited short circuit capacity of microgrids (Hooshyar and Iravani 2017). However, measuring a range of frequencies at fault current transient states could provide an effective protection method for microgrids with IBDGs (Liu, Bi, and Liu 2017). However, a high- or low-power quality depends on having a perfect sinusoidal or distorted waveform, respectively (Kamenka 2020). IBDGs could present low-power quality because PV arrays have individual current sources with independent DC current ripple of the converter ripple. Therefore, PV arrays and converter ripple currents are not synchronized and thus could produce subharmonics in the DC circuit that increase the total harmonic distortion in the current waveform (Halpin 2006). Therefore, protective relays and power meters that could measure voltages and currents with high sample rates in the electricity grid are crucial to detect high harmonics for electrical fault transients. The signal rate is measured in samples per cycle and can be calculated by Eq. (5-1),

$$SR = \frac{Samples}{cycle}, \tag{5-1}$$

where *SR* is the signal rate in samples per cycle.

Based on Eq. (5-1), the sampling frequency (*SF*) can be estimated by samples per second or hertz, replacing Eq. (5-1) with Eq. (5-2). Thus, in a 60 Hz power system, the sampling frequency (*SF*) can be calculated by Eq. (5-2) ,

$$SF = SR \times 60 = \frac{Samples}{cycle} \times 60\,, \tag{5-2}$$

where *SF* is the sampling frequency of the protective relay or power meter in samples per second or hertz, and *SR* is the sampling rate of the protective relay or power meter in samples per cycle.

To convert an analog wave to a digital signal, it must be measured at a regular frequency, which is the sample rate. If the sample rate is too low, it will not accurately express the original signal and will be distorted, or show aliasing effects, when reproduced. If the sample rate is too high, it will needlessly take up extra storage and processing resources. The Nyquist theorem (i.e., the sampling theorem) is the principle to accurately reproduce a pure sine wave measurement, or sample, rate, which must be at least twice its frequency (Das 2016).

$$f_s > 2 \times f_{max}\,. \tag{5-3}$$

From Eq. (5-3), the maximum measured frequency is

$$f_{max} = \frac{f_s}{2}, \tag{5-4}$$

where f_s is the sample rate or sampling frequency in hertz, and f_{max} is the bandwidth signal or maximum measured frequency in hertz.

From Eq. (5-4), if the sampling frequency of the protective relay or power meter is 4,000 Hz, the maximum frequency for an analog signal that could be measured based on the Nyquist theorem will be 2,000 Hz. Selecting power meters and protective relays with high sampling frequencies is very important to observe and study high harmonics during transient events (Piesciorovsky and Karnowski 2021). PV arrays with power electronics inverters can generate electrical fault currents over a wide range of frequencies (Piesciorovsky and Karnowski 2021). In modern electrical grids, advanced power meters (Schweitzer Engineering Laboratories 2022b) with a capacity to capture events of 512 samples per cycle are needed to study electrical fault events and understand the nature of transients for PV arrays.

5.3 PUMPED STORAGE HYDROPOWER

US developers finance pumped hydropower projects in two primary ways. Vertically integrated utilities finance construction through own equity and debt. Utilities operating in power markets tend to split the investment. Part of the cost, which was found in some instances to be around 20%, is financed through own investor equity. The other part is raised in the markets. Other sources, such as public bonds though public private partnerships or public development grants, were not found to be significant for open pit pumped hydropower. Some developers mentioned tax credit as a helpful but not critical component of the financial structure.

Access to markets for electricity and ancillary services must also be considered. The first form is revenue agreements that are usually implemented by regulated utilities in vertically integrated systems. In this case, a utility would file the revenue requirement details to a local regulator, and in the event of a positive decision include the development cost in its rate.

The second form of market access is through competitive markets for electricity and ancillary services. According to a series of industry stakeholder interviews, developers in the United States indicate that arbitrage revenue from electricity markets is not sufficient to cover the investment costs of building an open pit pumped hydropower project on former mine land. However, as revenues from ancillary services are factored in, a project becomes feasible. Ancillary services are defined broadly and depend on a market but could include frequency and voltage support, and a variety of reliability payments, compensated through capacity or reserve markets. According to investors, revenue from ancillary services could make up to 70% of total project operating income. Another 30% would come from arbitrage in electricity markets.

PSH represents the largest source of energy storage in the United States, accounting for 93% of utility-scale storage power capacity (GW) and more than 99% of electrical energy storage (GWh) in 2019 (Uria-Martinez et al. 2021). PSH energy storage systems operate by transferring water between an upper water body and a lower water body, generating electricity when the water flows downhill and using pumping power to return the water uphill for storage and later generation. Physically, projects may be operated as open-loop or closed-loop. Comparatively speaking, closed-loop systems offer several benefits, including fewer environmental impacts and a shorter licensing decision timeline (2 years). The vast majority (42 of 43) of currently operating PSH projects are open-loop; however, the wide majority of proposed PSH projects are closed-loop (79 of 96).

Although no operational PSH projects are currently sited on mine land, numerous pipeline projects have been proposed to utilize mine land. An estimated total of 13 PSH mine land projects are currently proposed in the development pipeline; all 13 projects are closed-loop designs. None have become operational, but one project (Eagle Mountain) has been issued a license by FERC. The rest either have been granted a preliminary permit or have a pending preliminary permit.

PSH projects for mine land may leverage surface mine land application (i.e., open pit PSH; Figure 5-15) or underground mine application (i.e., shaft PSH; Figure 5-16).

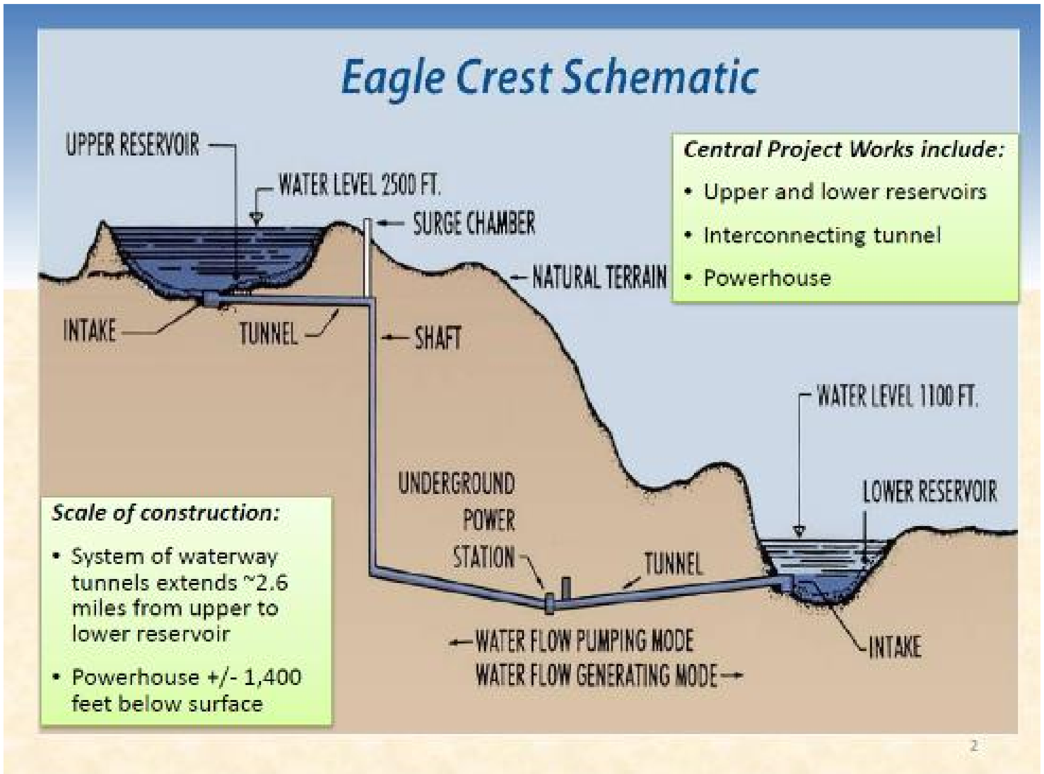


Figure 5-15. Example of surface mine PSH application using underground water conveyances. Source: image courtesy of Jeff Harvey, NextEra Energy Resources.

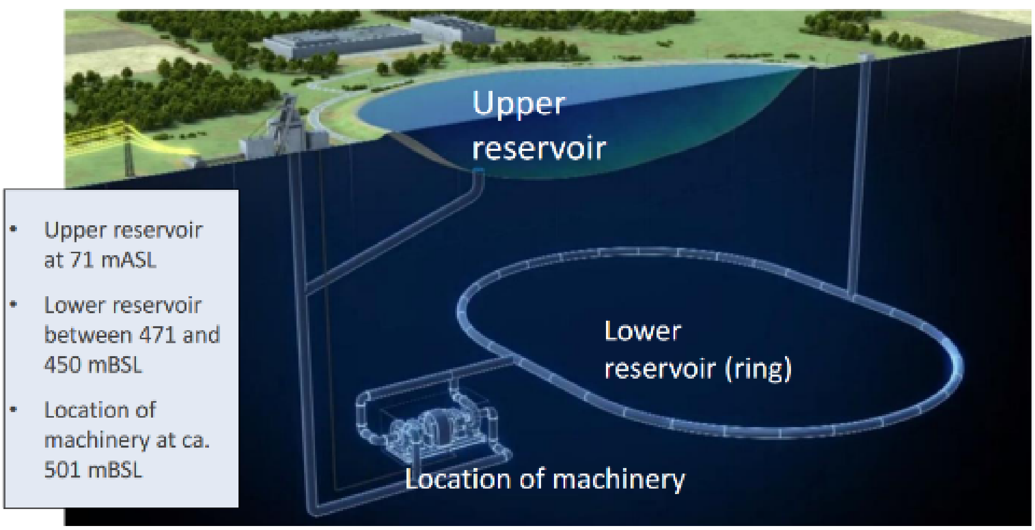


Figure 5-16. Example of underground mine PSH application. Source: image courtesy of Dr. André Niemann, University of Duisburg-Essen.

Site characteristics

The physical site characteristics that affect PSH project feasibility include reservoir storage volume, water flow rate, water hydraulic head, estimated installed (power) capacity, water quality, and seismic/geological stability and hydrogeology. Storage volume, flow rate, hydraulic head, and power potential are described more in the following technical section.

Water quality is a significant factor in the development of PSH in open pit coal mines for a variety of reasons. The first reason is that open pit mines naturally accumulate water, which requires occasional water releases, and would probably require water releases before the pits can be waterproofed and repurposed. The second reason is that if the waterproofing of the reservoirs is imperfect, that creates conditions for contamination of water from being in contact with potentially toxic substances.

Existing research (AECOM Australia 2019) suggests that water quality is mitigated for the inclusion of a wide range of chemicals, including As, Cd, Se, Pb, Zn, Mn, nitrogen, Cr, and sulfur. Water quality is further checked for pH and dissolved mineral solids.

Geological stability can present a limiting factor for the whole PSH setting. If the upper reservoir has been artificially built of the material from the main pit, this may create the conditions for subsidence of the walls of the reservoir (Wessel et al. 2020). The stability of both reservoirs would also be required to maintain waterproof properties.

The inflow of water to the open pit pumped hydropower reservoir during the construction stage is analyzed for velocity, shear stress, flow width, flow depth, stream power (AECOM Australia 2019). Existing research assumes that in the operating stage, reservoirs would be waterproofed using cement or asphalt liners to prevent the outflow of water and water contamination due to contact with toxic substances and to maintain water storage; use of geomembrane liners may also be effective. The drainage area characteristics may affect how much surface water can channel into the reservoirs. Significant rainfall events are seen as factors that can contribute to recharge of the reservoirs but may also cause an overflow and transport of sediment into the reservoirs. Subsurface water recharge is also a consideration, and many proposed PSH projects consider the use of subsurface water for the initial reservoir filling.

Geographical

Effective PSH development requires the presence of elevation differential. For surface mine PSH, this means finding mines within high-relief areas where an existing open pit may be paired with a newly constructed reservoir, or where two adjacent open pits are at suitably different elevations. Surface mines may also not be as suitable for considerably cold regions where ice effects may make operations challenging during winter months.

For underground mine PSH, geography is less of a factor, since an upper reservoir can be easily constructed, and the underground mine characteristics are not geographically constrained. Certain types of underground mines (e.g., metallic mines) may provide more suitable structural stability, so the geographic locations of such mines may mean more resource potential exists in certain regions. Proximity to existing transmission lines may prove an important factor, though the mines themselves are likely adjacent to such infrastructure.

Regulatory and permitting framework

The regulation of pumped hydropower on open pit mine land is partially done through local laws and partially through the federal requirements. There exists a FERC guidance (FERC 2019) that explains permitting of pumped hydropower projects on mine land which includes the description of regular and expedited licensing processes for closed-loop reservoirs. The main considerations highlighted in the guidelines include

- Geology and soil,
- Water resources,
- Fish and aquatic resources,

- Terrestrial habitat,
- Endangered and protected species,
- Tribal resources,
- Socioeconomics, and
- Aesthetics and recreation.

The license process requires documented evidence of consultations on the areas of concern with relevant stakeholders such as state and federal agencies, Indian tribes, local landowners, nonprofits. The objective of the stakeholder meetings is to identify issues and needs, conduct studies to identify project-related impacts, develop mitigation and enhancement measures.

Technical (design and engineering)

The primary design and engineering considerations for PSH development include storage volume, flow rate, hydraulic head, and power potential.

Water flow rate is constrained by the smallest of the upper reservoir storage volume and the lower reservoir storage volume. The other parameter to consider is the desired power generation duration. Typically, most PSH projects operate on a daily basis, generating power for 4–10 h (Kortarov et al. 2022) and using additional time during the day to return water to the upper reservoir.

A simplified calculation of total water flow rate can be performed according to Eq. (5-5). Total flow rate may be split among different penstocks to supply multiple pumps/turbines (or reversible pump-turbine units).

$$Q = V / t \tag{5-5}$$

where Q is the total water flow rate (cms), V is the minimum reservoir storage volume (m^3), and t is the flow duration (s).

The water hydraulic head varies as the upper and lower reservoirs are filled and emptied. Hydraulic head is measured as the elevation difference between the upper and lower reservoir surface water elevation, minor energy losses and water flows through the water conveyance system.

The turbine(s) and pump(s) installed in a PSH powerhouse are sized to meet the design head and flow for each unit. The power generated by an individual turbine is a function of water density, flow rate, gravity, and head, as calculated in Eq. (5-6).

$$P = 1000 * q * 9.81 * h, \tag{5-6}$$

where P is the power potential (W), q is the unit water flow rate (cms), and h is the water hydraulic head (m).

According to feedback received from technical experts during the Eastern Mine Land Workshop, a minimum head elevation of 500 ft is reasonable to assume to achieve attractive project feasibility. The higher the head and the higher the power potential, the greater the project feasibility.

PSH reservoirs require waterproofing (e.g., via reservoir liners) to ensure water volume is maintained, and must provide a means for excess water inflow to be spilled to avoid overtopping or flooding.

A PSH plant usually requires new transmission equipment, which usually includes a substation, but some projects also require new transmission power lines. This may be a direct consequence of expanding peak capacity of the site. Access to roads and laydown areas are needed during construction and to enable periodic maintenance and replacement of equipment.

PSH projects are often designed to last 50 years or more, with some components having a shorter design life. Other considerations such as generating equipment or open-loop vs. closed-loop structure of the PSH project are not specific to surface vs. underground mines and therefore are not covered through the separate review of existing research.

Economic

The exact costs of converting an abandoned open pit mine into PSH depend on the specific characteristics of the mine. However, the main cost components can be established based on existing research. The main cost areas include the following:

- Reservoir groundwork, waterproofing
- Waterway costs, tubes
- Generators, turbines, pump, network, communication
- Roads, transmission lines, substation equipment, security systems, landscape work
- Construction equipment, labor
- Insurance, financial interest

The main approach to evaluating the techno-economic feasibility of an open pit PSH project is using NPV (Witt et al. 2015). According to existing research, there are multiple ways to generate revenue from pumped hydropower systems. A pumped hydropower facility can sell its output at fixed contracts or through an open market, in the latter event total revenue stream can come from energy and ancillary services markets. Standby capacity represents another stream of revenue.

Economic viability of a PSH project follows economies of scale, with higher megawatt projects having lower per-kilowatt costs. Thus, a 1 GW project is likely to have a much lower cost per kilowatt compared with a 100 MW project (Figure 4-14).

Market

According to Koritarov et al. (2022), several market-related challenges face PSH development, including the following:

- Not having a capacity market—or having a poorly designed capacity market—is an obstacle for PSH developers, because capacity payments are a very important revenue stream for repaying the investment costs.

- PSH developers also face uncertainty related to future electricity market prices under conditions of large deployments of variable renewable energy generation, which have near zero marginal cost of operation. This may translate into uncertain revenues from energy/price arbitrage.

- The rules related to provisions and remunerations for grid services also vary from market to market. The key obstacle here is that PSH plants provide many grid services that are currently not remunerated in organized electricity markets. These are mostly system-wide services such as inertial response, reduced curtailments of variable renewable energy generation, reduced cycling and ramping of other units in the system, improved power system stability, increased reliability and resilience of grid operations, and reduced transmission congestion and transmission deferral benefits…

- To avoid or reduce revenue uncertainties, many IPP developers would prefer to establish long-term PPAs with local utilities for at least a part of their PSH capacity. These bilateral PPA contracts would allow for some steady revenue streams, while the remaining PSH capacity could be offered to the market. However, utilities are often reluctant to enter into long-term PPAs because they face many uncertainties as well.

- Most PSH projects tend to be large undertakings, with capacity ranging from several hundreds to over a thousand megawatts. This requires a large capital investment for project construction and sometime coordination of multiple owners/off-takers. The large initial capital expenditure increases project development risks, prolongs the investment payback period, and makes it more difficult to close financing. Many PSH developers (including utilities and IPPs), as well as financial lending organizations, are risk averse and prefer projects with smaller investment requirements and shorter payback periods.

- Most power system modeling tools do not represent PSH plants with sufficient detail and accuracy to capture the full range of benefits these plants provide to the grid.

Social considerations

The social considerations related to development of PSH include general social acceptance of large infrastructure projects and project-specific considerations. Like in other infrastructure and technology-based projects, information about social acceptance could be collected stakeholder sessions or representative population surveys. The typical areas assessed for PSH projects include demographics, perception of own region, openness to large infrastructure development, openness to renewable energy and storage in the particular community, anticipation of benefits and challenges related to the project, sources of news about the project.

The general acceptance of infrastructure projects on mine land is related to a number of factors. One factor is the public perception of coal mines and self-perception as a mining community. An underground mine should ideally be operational at when it starts being repurposed for an underground pumped hydropower plant. Therefore, the local communities may oppose the conversion of an active mine to something which is unrelated to mining activities. A study from the German Ruhr area (Grunow et al. 2013) found that some values, such as attachment to local traditions, are supported by about 90% of respondents. A transition from coal is only viewed positively by about 50% and redevelopment of coal mines for commercial or industrial purposes was viewed positively by about 60% of the population. Notably, these results were a consequence of traditional rather that anti-environmental mindset. These results were obtained in the area where more than 70% of the population supports PV and wind and more than 40% of the population negatively perceives coal mining, fracking, and nuclear energy. Environmental values themselves do not have the same positive effect on acceptance of pumped hydropower as they have on acceptance of renewable energy sources such as PV or wind.

Another component of general social acceptance is public perception of large industrial and infrastructure projects. The issues highlighted in existing industry experience include lack of trust in the entities involved in large projects, such as regional executive branch, corporate developers, and regional policy makers. By contrast, local nonprofits were found to enjoy a higher level of trust from residents. One more area of distrust is the siting and construction process. Process-related concerns include overspending, lack of information about the site and status of construction, lack of consideration of local feedback.

Project-specific considerations include concerns for health, property, and environment. Health and environment aspects usually include the concerns for water quality due to the development of PSH on former mine land. Damage to property reflects concerns about geological stability and the existence of the upper reservoir. Notably, the same concerns underlie the social and legislative efforts across different countries, including the United States. Visibility was less of an issue compared with other technologies. The lack of concern about visibility could be because most equipment is located under the surface and is therefore not visible to the residents.

There is industry evidence that public awareness about the technology facilitates public acceptance of underground PSH projects. Grunow et al. (2013) found that 80% of residents who were informed about PSH technology supported the project, compared with the average acceptance of 50%. The public also expressed an interest and judgement with regard to the actual configuration of the project. When offered to rate two types of technical plans for the project, 75% of the residents showed preference for one of the types.

6. SUMMARY

This report summarizes the results of a study carried out by ORNL, in collaboration with Lawrence Berkeley National Laboratory and NREL, to assess the potential of deploying clean energy technologies on current and former mine land in the United States. The study was structured into a series of activities that included performing a resource assessment for each clean energy technology; identifying relevant analysis tools, data sets, and technology gaps; reviewing case studies in the United States and abroad; illustrating conceptual site models; and conducting interviews and holding three workshops with relevant stakeholders, including utilities, project developers, community organizations, labor groups, and local, state, and federal agencies.

Considering the large number of mine land sites in existence in the United States (>17,000), great opportunity exists for generating more than 85 GW of clean electricity on these sites through the deployment of clean energy technologies, including solar PV, geothermal, fossil-fueled power plants with CCUS, and advanced nuclear technologies. Furthermore, opportunities exist for combining one or more of the aforementioned clean energy technologies with microgrids and energy storage, including shaft and pit PSH, compressed air storage, and batteries. Opportunities for deploying CO_2 reduction technologies, such as DAC, on mine land were also reviewed.

For each clean energy technology reviewed, this report addresses physical site requirements; infrastructure access; regulatory and decommissioning considerations; economic, resource, and social considerations, and the feasibility of deploying these clean energy technologies on both brownfield land of former mines and on operating mines. The study revealed high public acceptance for the deployment of these technologies because they can offer financial profits, tax revenue, jobs, and community benefits, provided there is sufficient early planning and broad stakeholder engagement.

This report identifies analytical tools, mathematical models, and other resources, and illustrates conceptual site models that would be of great value for parties interested in deploying clean energy technologies on current and former mine land.

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APPENDIX A. OVERVIEW OF MINING METHODS

The following material draws heavily from The Pennsylvania State University College of Earth and Mineral Sciences John A. Dutton e-Education Institute materials for MNG 230, "Introduction to Mining Engineering."

A traditional taxonomy of mining methods classifies them according to surface and underground methods. Surface methods include the mechanical methods of open pit, open cast (i.e., strip mining), quarrying, and auger, as well as the aqueous methods of hydraulic, dredging, solution, and heap leaching. Underground methods are typically split between three types of mining: (1) the unsupported methods of room and pillar, shrinkage stoping, and open stoping; (2) the supported methods of cut and fill; and (3) the caving methods of block caving, sublevel caving, and longwall.

Mine operators select between surface and underground methods based on how they answer the following questions: "Are we accessing [the ore body] from the surface, or is it too deep beneath the surface, such that we can only economically access it from underground?"[44] Module 4.4 of MNG 230 provides the decision tree displayed in Figure A-1 to illustrate which mining method is typically used for which depth of deposit and thickness of overburden, according to the surface and underground division of methods.

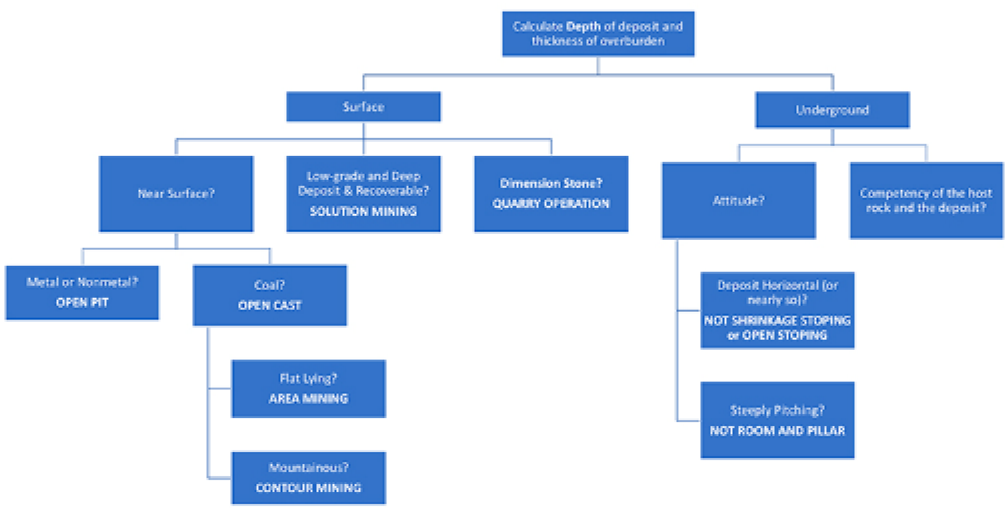

Figure A-1. Sample decision tree for determining the mining method after depth of deposit and thickness of overburden is calculated. Source: The Pennsylvania State University, licensed under CC BY-NC-SA 4.0.

The vast majority of mines in the United States are surface mines. This holds across the mining sectors of coal, metal, nonmetal, stone, and sand and gravel. Figure A-2 portrays the number of surface and underground mines in the United States by sector. This figure was generated by The Pennsylvania State University using data provided by MSHA.

[44] https://www.e-education.psu.edu/geog000/node/825

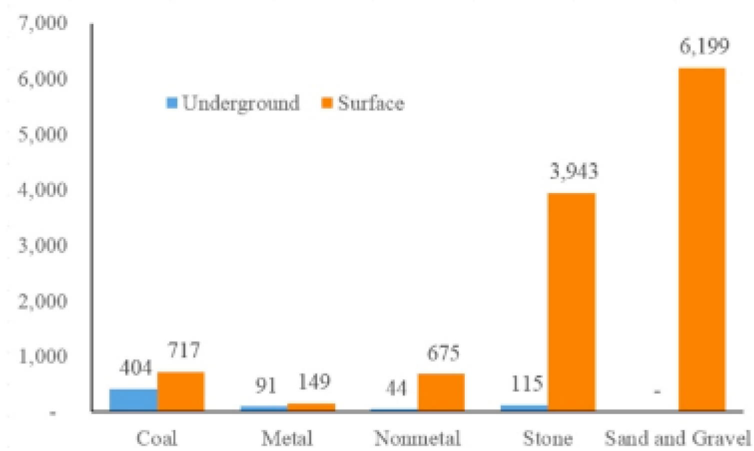

Figure A-2. Number of surface vs. underground mining operations for US mining sectors. Source: The Pennsylvania State University, using MSHA data.

The following definitions of mining methods are direct quotations from Modules 4.3.1 (Surface Mining Methods) and 4.3.2 (Underground Mining Methods) of MNG 230. The only exceptions are the footnotes which define area and contour mining; these come from materials compiled by American Mine Services LLC.

Surface Mining Methods – Mechanical

- Open pit mining: This type of mining is used for near-surface deposits, primarily metal and nonmetal. The overburden is hauled away to a waste area and a large pit is excavated into the ore body. The depth of the pit is increased by removing material in successive benches. A few examples of commodities mined by this method would include Fe and diamonds.

- Open cast mining: Open cast mining is also known as strip mining and is used for bedded deposits, and most commonly for coal. Although it is similar to open pit mining, the distinguishing characteristic is that the overburden is not hauled away to waste dumps; but rather, it is immediately cast directly into the adjacent mined-out cut. There are two important sub methods for open cast mining. One is known as area mining,[45] and is applicable when the terrain is relatively flat; and the other is contour mining,[46] better suited for mountainous regions. A few examples of commodities mined by this method include coal and PO_4^{-3}.

    - Area mining: "Extracts ore over a large, flat terrain in long strips. The overburden of rocks and soil is dropped in the previous strip so that long gaps aren't left in the earth after mining is complete."

[45] "Extracts ore over a large, flat terrain in long strips. The overburden of rocks and soil is dropped in the previous strip so that long gaps aren't left in the earth after mining is complete." https://americanmineservices.com/types-of-surface-mining/

[46] "Follows the contours of outcrops and hilly terrains. Usually, the mineral seam follows the contour of the outcrop, and the overburden is removed carefully along the seam in much smaller and custom shaped excavations rather than long strips." https://americanmineservices.com/types-of-surface-mining/

- Contour mining: "Follows the contours of outcrops and hilly terrains. Usually, the mineral seam follows the contour of the outcrop, and the overburden is removed carefully along the seam in much smaller and custom shaped excavations rather than long strips."

- Quarrying: Quarrying is a method of extracting dimension stone. The term dimension stone encompasses certain stone products used for architectural purposes such as granite countertops, marble flooring, and monuments, among a few others. The goal in the mining of these products is to remove large slabs that can be cut and machined to exacting architectural applications. Unlike open pit mining in which benching is required to prevent failure of the sides or pit slopes, the high strength and competency of the rock mass in quarries is such that vertical walls of 1000' or more can be excavated. Now that I've given you the classical mining engineering definition of quarrying, you should be aware that just about everybody uses this word, "quarry" to describe any open pit operation in stone!

- Auger mining: This is a method to recover additional coal from under the highwall of a contour mine when the ultimate stripping ratio has been achieved in open cast operations. It is sometimes referred to as secondary mining because it is done after the open cast mine has reached an economic limit.

Surface Mining – Aqueous

- Hydraulic mining: Hydraulic mining is used for a limited class of deposits that are characterized as loosely consolidated, such as placer-type deposits. A high-pressure water canon is used to dislodge the deposit, and the resulting solution is either pumped to a processing plant or a gravity separation is performed at the mine site using something like a sluice. A few examples of commodities mined by this method include Au and kaolin.

- Dredging: This method is used for underwater recovery of loosely consolidated materials using a floating mining machine known as a dredge. In some cases, the deposits are naturally underwater, while in others the area is flooded, creating an artificial lake on which the dredge operates. A few examples of commodities mined by this method include sand and gravel.

- Solution mining: Solution mining is used to recover deep deposits that would be uneconomical using underground methods, but only if the ore can be easily dissolved by a solvent. In this method, holes are drilled from the surface into the deposit. A solvent is pumped down one hole, and the resulting solution with the dissolved mineral is pumped out another hole. This solute or pregnant liquor, as it is often known, is processed to extract the mineral of interest. In some cases, only one hole is used, but the hole has an inner and outer section to separate the in-going solvent from the out-coming solute. Water, acid, and steam are common solvents. A few examples of commodities mined by this method include uranium and sulfur.

- Heap leaching: Heap leaching was used many years ago as a method to recover very low percentages of metal remaining in the tailings from mineral processing plants. Large piles (i.e., heaps) of the tailings of low-grade ore were created, a solvent was allowed to drip and percolate down through the heap, and then the pregnant liquor was recovered and processed. In this fashion, it is a secondary method. In recent years it has been used with increasing frequency to recover high-value metals such as Au from very low-grade ores. A few examples of commodities mined by this method include Cu and Au.

Underground Mining – Unsupported

- Room and pillar mining: This method of mining is used to recover bedded deposits that are horizontal or nearly horizontal when the ore body and the surrounding rock are reasonably competent. Parallel openings are mined in the ore (i.e., rooms), and blocks of ore (i.e., pillars) are left in place to support the overlying strata. Other than the pillars, little artificial support is required and often consists of bolts placed into the overlying strata to pin the layers together, making them behave like a strong laminated beam. A few examples of commodities mined by this method would include coal, Pb, limestone, and salt. Historically, if the pillars were irregular in size and placement, which is more likely to occur in certain metal and nonmetal deposits, this method was known as stope and pillar, rather than room and pillar. You will still hear the word stope and pillar being used, but the distinction is now largely irrelevant. *This method accounts for the vast majority of all underground mining in the United States, and likely the world*.

- Shrinkage stoping: Shrinkage stoping is used to recover steeply dipping ore bodies when the ore and host rock are reasonably competent. A stope (i.e., a large section of the mine where active production is occurring) is mined, but the broken ore is not removed, but rather is left in place to support the walls of the stope until the time when all the broken ore will be removed. Since rock swells (i.e., increases in volume when it is broken), it is necessary to draw off some of the broken ore as the stope is progressively mined. The name of this method derives from this drawing off or shrinkage of the stope. A modern and important variant of this method is known as vertical crater retreat mining. A few examples of commodities mined by this method include Fe and Pd.

- Open stoping: This type of mining is used to recover steeply dipping ore bodies in competent rock. The ore is removed from the stope as soon as it is mined. Sublevel stoping and big-hole stoping are the important variants in use today. A few examples of commodities mined by this method include Fe and Pb/Zn.

Underground Mining – Supported

- Cut and fill: Cut and fill is used to recover ore from weaker strength materials, in which the openings will not remain stable after the ore is removed, and the overlying strata cannot be allowed to cave. A slice of the ore body is mined and immediately after the ore is removed, backfill is placed into the opening to support the ore above. The next slice is removed, the cut is then backfilled, and the process repeats. As you might imagine, this is a very expensive method to use, and consequently, it would be used only for the recovery of high value ores. An example of a commodity mined by this method is Au.

Underground Mining – Caving

- Block caving: This method is used in weak and massive ore bodies, in which the ore is undercut, and then as the broken ore is removed the remainder of the ore body collapses into this void, and as more ore is withdrawn, the caving continues. Typically, the host rock is fairly strong, although ultimately it tends to cave into the void created from removing the ore. The fracturing and caving often break through to the surface.

- Sublevel caving: This type of caving is used in strong and massive ore bodies in which the host rock is very weak and quickly caves into the void created by removing the core. As in block caving, the cave will ultimately reach the surface.

- Longwall mining: Longwall mining is a type of caving, applied to a horizontal tabular deposit such as coal. While block and sublevel caving are essentially vertically advancing metal mining methods, longwall mining is applied to relatively thin and flat-lying deposits – most often coal, but occasionally an industrial mineral such as trona. The coal seam is extracted completely between the access roads, and then as mining retreats, the overlying strata caves into the void left by removing the coal.

APPENDIX B. MINERAL MINES SUMMARY

Table B-1. Federal databases – mine land

Source	Database description	URL
EPA	Abandoned hard rock mines and mineral processing sites listed in the Superfund Enterprise Management System	https://www.epa.gov/superfund/abandoned-mine-lands-site-information
BLM	Inventory of known AML on public lands. Most of the sites are abandoned hard rock mines. As of January 5, 2017, the inventory contained over 52,200 sites and 97,600 features. *It is BLM AML Program policy to not release the specific locations of AML sites and features.*	https://www.blm.gov/programs/public-safety-and-fire/abandoned-mine-lands/blm-aml-inventory
Office of Surface Mining Reclamation and Enforcement	The National Mine Map repository has over 150,000 maps of closed and/or abandoned, surface, and underground mines throughout the United States.	https://mmr.osmre.gov/MultiPub.aspx
Office of Surface Mining Reclamation and Enforcement	e-AMLIS is a national inventory that provides information about known AML features including polluted waters. The majority of the data in e-AMLIS provides information about known coal AML features for the 25 states and 3 tribal AML programs approved by the Surface Mining Control and Reclamation Act of 1977. e-AMLIS also provides limited information on non-coal AML features, non-coal reclamation projects, and AML features for states and tribes that do not have an approved AML program.	https://amlis.osmre.gov/Map.aspx
USGS	Prospect- and mine-related features on USGS topographic maps	https://mrdata.usgs.gov/usmin/
USGS	Mineral Resources Online Spatial Data: Interactive maps and downloadable data for US mineral deposits and mineral resources (past and present mines, mineral prospects)	https://mrdata.usgs.gov/general/map-us.html

Table B-2. State databases – mine land

State	Description	URL
Alabama	Directory of underground mine maps	https://labor.alabama.gov/Inspections/Mining/Directory_of_Mine_Maps_2013.pdf
Alaska	AML program	https://dnr.alaska.gov/mlw/mining/aml/
Arizona	Web-based map of active mines in Arizona	https://uagis.maps.arcgis.com/apps/webappviewer/index.html?id=9eceb192cd86497e8eed04113302db8b
California	Abandoned Mine Lands Unit	https://www.conservation.ca.gov/dmr/abandoned_mine_lands
Colorado	Inactive mine reclamation program	https://drms.colorado.gov/programs/inactive-mine-reclamation-program
Colorado	GIS database for active and historic hard rock and coal mines	https://drms.colorado.gov/data-search
Idaho	GIS database of the mines and prospects of Idaho, covering nearly 9000 mining properties	https://www.idahogeology.org/product/dd-1
Illinois	Web-based map of Illinois coal mine permit locations (includes active and AML sites)	https://maps.dnr.illinois.gov/portal/apps/webappviewer/index.html?id=381593 88ea94457186846bec1beb16ab
Indiana	Web-based coal mine information system for current and abandoned mines	https://indnr.maps.arcgis.com/apps/webappviewer/index.html?id=f30ca6a781cb4209b6e614789ca7185b
Iowa	Web-based minerals map of Iowa	https://iowa.maps.arcgis.com/apps/webappviewer/index.html?id=24af59f077c44e2bbc60834f27cbc84f
Kansas	AML program	https://www.kdhe.ks.gov/550/Abandoned-Mine-Land-Program
Kentucky	Web-based coal mine map of Kentucky	https://eppcgis.ky.gov/minemapping/
Maryland	KMZ files of coal and non-coal surface mine locations in Maryland	https://mde.maryland.gov/programs/land/mining/Pages/mapping.aspx
Missouri	Web-based map of AML in Missouri	https://modnr.maps.arcgis.com/apps/webappviewer/index.html?id=d45c80048872499e8eef28c136cfb165
Montana	AML web mapping application	https://gis.mtdeq.us/portal/apps/webappviewer/index.html?id=c7c08b21f7e74a5888eec29629fe9736
New Mexico	Web-based map of registered mines in New Mexico	https://nm-emnrd.maps.arcgis.com/apps/webappviewer/index.html?id=6d4b64a5752f4b4bb53000e999ff6a24
Nevada	Web-based map of active and historic mining claims in Nevada, including commodity type and land status	https://ndom.maps.arcgis.com/apps/webappviewer/index.html?id=622e18db0e1340d5a6d5d59404faad8e
North Dakota	Web-based map of AML in North Dakota	https://ndgov.maps.arcgis.com/home/webmap/viewer.html?webmap=0c4eb5ce19a84a069c1d04b449c39d43
Ohio	Map of AML in Ohio	https://ohiodnr.gov/wps/wcm/connect/gov/a3995636-2325-4405-96a9-f5fccf3c90a6/%28Map+of%29+Ohio%27s+Abandoned+Mines.pdf?MOD=AJPERES&CONVERT_TO=url&CACHEID=ROOTWORKSPACE.Z18_K9I401S01H7F40QBNJU3SO1

State	Description	URL
		F56-a3995636-2325-4405-96a9-f5fccf3c90a6-o2US7su
Oklahoma	Catalog of historic underground mining maps (by county)	https://mines.ok.gov/historic-underground-mining-maps
Oregon	Geospatial database of mineral occurrences, prospects, and mines in Oregon (MILO-3)	https://www.oregongeology.org/milo/index.htm
Texas	AML program	https://www.rrc.texas.gov/surface-mining/programs/abandoned-mine-land-program/
Utah	Web-based map of active and retired mineral mines in Utah	https://ogm-public-data-utahdnr.hub.arcgis.com/apps/mineral-mapper-external/explore
Virginia	Web-based map of active and AML	https://energy.virginia.gov/webmaps/MineralMining/
Washington	Web-based map with locations of mines with active surface mining reclamation permits	https://geologyportal.dnr.wa.gov/2d-view#erpl?-14049968,-12889348,5650448,6397696?Active_Surface_Mine_Permit_Locations,Active_Surface_Mine_Permit_Sites
West Virginia	Web-based map of underground and surface coal mines	http://www.wvgs.wvnet.edu/GIS/CBMP/all_mining.html
Wyoming	Web-based map of mines and mineral resources of Wyoming	https://portal.wsgs.wyo.gov/arcgis/apps/webappviewer/index.html?id=9f8e71851d0c421dbeb8ed608bc2dd48