APPENDIX F:

SOLAR ENERGY TECHNOLOGY OVERVIEW

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SOLAR ENERGY TECHNOLOGY OVERVIEW

F.1 INTRODUCTION

Solar energy technology can be defined broadly as those activities, applications, or devices designed to harness energy from the sun to perform useful work. By that measure, humans have been devising and applying solar energy technology for centuries, beginning with the use of magnifying glasses and mirrors to concentrate the sun's rays to start fires and light ceremonial torches as early as the 7th century B.C. The first application of passive solar heating was in Roman bathhouses of the 1st through the 4th centuries A.D. The first solar electric or photovoltaic cell was produced in 1839, and the first solar water heater was manufactured in 1891. Photovoltaic technology was advanced in the United States in the 1950s, and the first telecommunications satellite, Telstar 1, was powered by photovoltaic panels in 1962. The first photovoltaic-powered residence was constructed in 1973; and a rapid expansion of solar energy technologies that began in the early 1980s continues today.[1]

This overview focuses only on the use of solar energy to produce electric power for utilities by using:

- Photovoltaics to convert the sun directly into electricity, and

- Concentrated solar power that creates steam to drive a conventional generator to produce electricity.

Other uses of solar energy include direct sunlight to heat and light living and working spaces and concentrated sunlight to heat water.

F.1.1 Scope of Overview

In recent years, technological advances, the rising costs of energy, as well as government regulations and incentives for renewable energy technologies, have increased interest in renewable energy technologies, including solar. This overview does not discuss all variations of energy-producing solar technologies that exist or that could be built. Instead, the focus is on two technology categories that are believed to hold the greatest potential for generating large

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[1] For more information on the history of solar technology development, see *The History of Solar* online at http://www1.eere.energy.gov/solar/pdfs/solar_timeline.pdf. Accessed Jan. 1, 2009.

amounts of electricity that can be delivered to the nation's electric grid within the 20-year planning horizon of the Solar programmatic environmental impact statement (PEIS).[2]

These solar electric categories are

1. Concentrating solar power (CSP) (or solar thermoelectric), and

2. Photovoltaic (PV) (or solar electric).

(See the text box for naming conventions for solar energy technologies.)

Naming Conventions for Solar Energy Technologies

For the purpose of this PEIS, solar energy technologies designed to produce electrical power are placed in one of two categories: "solar thermal technologies" and "solar electric (or photovoltaic) technologies."

The first category comprises solar thermal technologies that create electrical power by using the sun's energy to capture and manipulate heat to produce steam to drive a conventional steam turbine/electric generator set (STG) or to power an external heat engine that produces mechanical energy to drive a generator. Typically some means of concentrating the incident solar energy is used to improve the efficiencies of thermal technologies, such as reflecting or concentrating mirrors. This category of technologies is commonly referred to as "concentrating solar power," or CSP.

The second category comprises solar cell technologies that create electrical power by directly converting the photons in sunlight to electricity. This is called photovoltaic (PV) technology because it capitalizes on the "photovoltaic effect," which is the ability of certain materials to produce a flow of electrons when excited by sunlight. PV is also referred to as "solar electric technologies."

Concentrating photovoltaics (CPV) are a variation of PV-based technologies. CPV uses concentrating devices to further increase the amount of sunlight exposure on each solar cell than the area of the cell would otherwise receive. Placing the emphasis on the concentrating aspects, some categorize CPV with solar thermal technologies that also utilize some concentrating feature and consider all of these as CSP. This PEIS, however, identifies CPV as a PV or solar electric technology, rather than a CSP. The CSP category is reserved for technologies that involve the conversion of solar thermal energy to electricity.

Hybrid solar facilities are classified in this report as facilities that get their electricity from a combination of solar thermal technology and fossil-fuel–fired (e.g., coal or natural gas) power-generating equipment.

Some solar technologies can be categorized by their ability to produce dispatchable power (i.e., power readily available at all times to the grid operator, achieved in most instances through the use of thermal storage systems) rather than by the way in which they interact with the sun. Although dispatchability is a desirable operational characteristic for utility-scale solar facilities, it does not distinguish the technology. So, while various options for improving a solar facility's dispatchability are discussed, dispatchability is not used in this report as a means to categorize technologies.

[2] Various feasibility studies have been performed to explore other energy-related applications for solar technology (e.g., the production of hydrogen through electrolysis of water, the production of process steam for industrial applications, or the use of solar-produced heat to support thermochemical reactions). All such applications are considered outside the scope of this PEIS.

Within the two major technology categories (CSP and PV), five broad categories are reviewed in this overview:

- CSP technologies
  - Parabolic trough and compact linear Fresnel reflector (CLFR)
  - Solar power tower
  - Solar dish engine

- PV technologies
  - Flat-plate PV
  - Concentrating PV

The scale at which any solar energy technology is used to produce electricity can vary greatly and depends on the intended end use of the power being produced. The scope of this PEIS is limited to those technologies (listed above) that can produce utility-scale electrical power on the order of 20 MWe[3] for connection to the nation's medium- and high-voltage electric transmission and distribution grids.

Solar energy technologies that generate electricity used locally to satisfy relatively minor power demands are known as distributed, isolated, or off-grid applications. Some small-capacity installations are not connected to the electric grid, while others, primarily PV systems on residences or commercial buildings in urban or suburban areas, have the ability to return excess or unneeded electricity to the local electric distribution grid.[4] All such applications are characterized as having relatively low power-generating capacities (on the order of hundreds of watts or kilowatts, up to a few megawatts, maximum), and although they can be very effective and efficient in the individual applications for which they were designed, they are not included in the scope of this PEIS.

One inherent limitation of solar energy technologies is that power can be produced only when the sun is shining. Furthermore, the rate at which power is produced is directly related to the intensity of the solar radiation (or insolation) reaching the solar collectors (see text box). Consequently, during cloudy periods or at night, power production is severely reduced or stops entirely. Depending on the location and the utility, this intermittency in power generation can result in instability of the electricity grid to which the solar power facility is connected. Two methods to address the lack of dispatchability and reliability inherent in solar power generation are available for some CSP facilities: (1) incorporating thermal energy storage (TES), which

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[3] Arbitrarily, 20 MWe (net) is selected as the lower limit of utility-scale electrical power generated expressly for delivery to the grid. Obviously, the capacity of any solar energy facility is dependent on many factors and changes over the course of a day, a season, or a year regardless of its technology, geographic location, or design. The nominal capacity of 20 MWe (net) is understood to mean the peak power-generating capacity of the facility, expressed in watts as Wp minus all auxiliary, internal (parasitic) loads. In this document, MWe is used synonymously with MW (i.e., no thermal power [MWt] is discussed).

[4] The process of reverse power flow is known as net metering. Many states have adopted net metering policies that require utilities to purchase from or otherwise credit the customer for this reverse power. Net metering is available in 42 states and the District of Columbia. More details about state programs are available at http://apps3.eere.energy.gov/greenpower/resources/maps/netmetering_map.shtml. Accessed Jan. 5, 2009.

Insolation and Its Importance to Solar Technologies

Insolation is the solar radiation that reaches the earth's surface. It is typically represented as energy density and measured in units of watts per square meter (W/m^2) [$joules/ft^2$] per minute.

It represents the total electromagnetic energy contained in the incident sunlight. The sun's insolation is greatest over the equator—the more insolation, the higher the temperature. Factors that affect insolation are the angle of the sun, the distance between the sun and the earth, and the duration of daylight. A measure of insolation at any given location on the earth's surface must account for both daily and annual changes in the sun's angle of incidence. Changes in insolation levels over the course of the day are expressed as kilowatt hours per square meter per day (kWh/m^2 day). This daily average power-generating potential is a more meaningful number for estimating the potential of a location for solar power production. To account for variations in weather (cloud cover and airborne contaminants can both dramatically reduce solar energy reaching the ground), averaging insolation over many years provides a reliable number for estimating insolation potential for any given location.

The National Renewable Energy Laboratory (NREL) and National Aeronautics and Space Administration (NASA) maintain insolation data for the entire United States. (The NREL data sets can be accessed at http://www.nrel.gov/rredc/solar_resource.html. The NASA database can be accessed at http://eosweb.larc.nasa.gov/cgi-bin/sse/grid.cgi?uid=3030.) Computed in 2000, the 10-year insolation averages (expressed in $kWh/m^2{\cdot}day$) for some locations within the study area of the PEIS are Los Angeles, California, 5.40; Phoenix, Arizona, 5.38; Las Vegas, Nevada, 5.30; Albuquerque, New Mexico, 4.97; and Salt Lake City, Utah, 4.53. The effect of latitude on variability of insolation values can be observed by reviewing the monthly average values for any location. For example, for Phoenix, values (in $kWh/m^2{\cdot}day$) ranged from a low of 2.75 in December to a high of 7.7 in June, while for Anchorage, Alaska, values ranged from 0.12 to 4.58.

Solar technology designers must consider critical factors such as insolation and its variations over the time of day at a candidate location. Changes in insolation over time affect both the rate and the characteristics of the power being generated. These impacts can be overcome by applying devices that can reorient themselves to changing angles of incident sunlight, sophisticated system monitoring capabilities, and complex power conditioning equipment. However, these features increase initial installation and maintenance costs over a system's lifetime, so compromises are likely to be made that will influence the power-generating capacity of the resulting facility.

utilizes a system to store some of the heat captured in the solar field for delayed production of steam, and (2) combining the CSP facility with conventional fossil fuel–fired power-generating equipment, and using combined conventional steam turbine generators (STGs) and cooling systems. At this point in its development, TES is not practically available for CSP solar dish engines[5] or solar PV systems, because each uses fundamentally different mechanisms to produce electricity. Systems that incorporate TES are discussed for parabolic trough and power tower facilities in Section F.2.4.4. For informational purposes, the potential array of fossil fuel and parabolic trough or power tower hybrid systems is discussed in Section F.2.4.5, although the environmental impacts of the fossil fuel–fired portions of such combinations are not evaluated in this PEIS.

[5] However, U.S. Department of Energy (DOE)-funded research in TES includes development of TES applications for solar dish engines. See Section F.2.4.3 for details.

F.1.2 Organization of Overview

Sections F.2 and F.3 provide brief descriptions of each of the five technology categories addressed in this PEIS (parabolic trough [including CLFR], solar power tower, solar dish engine, flat-plate PV, and concentrating PV), including

- How each technology produces electricity and the major components that a facility would need to produce electricity at the utility scale;
- The current state of commercial solar technologies; and
- The environmental footprint of a utility-scale facility, identifying key resource demands.

Some of the key resource demands are estimated by using parameters identified in currently proposed solar energy facility documentation. Information pertaining to design parameters for specific projects is meant to be representative of technologies with the greatest potential to generate utility-scale solar energy over the next 20 years. The facilities described in this appendix are in various stages of certification, and the parameters are subject to change. The parameters included in this overview were initially drawn from project applications, and have been revised to reflect data current as of February 2010.

Solar facilities also will need to connect to the electricity transmission grid. A discussion of required activities for transmission line construction and associated considerations is provided in Section F.4.

F.2 CONCENTRATING SOLAR POWER (CSP) TECHNOLOGIES AND FACILITIES

F.2.1 Basic Types of CSP Facilities

CSP has historically been called solar thermal electric or thermoelectric power since all variations are designed to convert the sun's energy to heat and then apply that heat in various ways to produce electricity. CSP technologies are distinguished by three basic design architectures for reflecting and concentrating solar energy:

1. Line-focus systems that concentrate solar energy along a line-shaped receiver, typically an oil-filled pipe positioned at the focus of parabolically shaped reflectors (parabolic trough systems) or along the focus of a parallel array of nearly flat mirrors acting as concentrators (the CLFR);

2. Point-focus systems that concentrate solar energy to a point receiver by means of flat-plate mirrors focusing reflected light on a receiver located at the top of a centrally located tower (solar power tower systems); and

3. Point-focus systems that use a parabolic-shaped reflector dish to focus the sun's energy on a point receiver/external heat engine/generator located at the focal point of the dish (solar dish engine systems).

To produce heat, all CSP technologies utilize direct normal insolation (DNI) only. That is, they use sunlight that directly strikes the reflecting/concentrating surface, rather than global insolation, which includes sunlight that has been refracted or diffused by clouds, airborne dusts, or the ground. Thus, for optimal performance, the reflective surfaces of CSP technologies must track the sun so that they reflect its rays to a line or point focus over the course of the day, and reflectors and/or concentrators must exhibit good optical characteristics.[6]

Parabolic trough and solar power tower CSP systems typically utilize a heat transfer fluid (HTF) (usually synthetic oil in the case of parabolic trough facilities and molten salt in the case of power tower facilities) to transfer the heat generated at the solar collectors to a heat exchanger, where steam is produced to drive a conventional STG. The CLFR system dispenses with the HTF, making steam directly at the solar field for delivery to the STG. The power block of a solar thermal facility containing the STG and other related power-generating and power management equipment is virtually identical in both form and function to the power block of fossil fuel and nuclear power plants that also use steam to produce electricity. The solar dish engine is unique among CSP technologies in that it uses the sun's heat not to produce steam but to expand a gas against a piston, generating mechanical energy that drives an electric generator or alternator. Although all CSP systems rely on their ability to collect and concentrate the sun's energy and convert it to heat, point-focus systems such as solar power towers and solar dish engines can attain greater degrees of concentration of the sun's energy than can troughs. By using different working fluids and power cycles, these systems generally operate at higher temperatures and higher efficiencies than parabolic troughs. Nevertheless, among CSP technologies, parabolic trough facilities have enjoyed the greatest degree of development and utility-scale application to date.

One thermal electric technology does not involve production of steam; this technology uses organic Rankine cycle (ORC) turbines coupled to conventional generators. Instead of accepting steam from a remote source, ORC turbines use heat to boil an organic working fluid contained in the reservoir of a closed system, allowing the resulting hot expanding vapors of the working fluid to drive the turbine-generator set. In doing so, the working fluid loses sufficient thermal energy to return to its liquid state and, after further cooling, is returned to its reservoir,

6 To ensure optimal year-round performance, reflecting surfaces must remain precisely perpendicular to the sun's DNI over the course of both the day (azimuth tracking) and the year (elevation tracking). Virtually every grid-connected utility-scale CSP facility can be expected to have at least single-axis, and more likely dual-axis, tracking capability. Either of two methods of dual-axis tracking can be used: (1) azimuth-elevation tracking, which rotates the dish in a plane parallel to the earth's surface over the course of the day, and up and down to reflect the changing position of the sun in the sky with the seasons, and (2) polar tracking, which rotates the dish about an axis that is parallel to the earth's rotational axis at a constant rate of 15º per hour, matching the earth's rotation, and then simultaneously rotates the dish about the declination axis (perpendicular to the polar axis) at a rate of 0.0016º per hour (approximately ± 23.5º over the course of a year). Reorienting the reflecting surface by either tracking method is typically accomplished by means of electric motors or hydraulic actuators, either system being computer-controlled and preprogrammed against the facility's specific location.

allowing the process to repeat. ORC turbines enjoy many industrial applications, recovering otherwise wasted heat and converting it to electrical power or mechanical energy. They offer a number of advantages, including: the ability to produce power from relatively minor sources of heat; minimal internal corrosion issues due to the absence of water; thermal efficiencies as high as 85%; and extended mechanical life due to relatively slower rotational speeds compared to conventional STGs. Perhaps most importantly for CSP applications in water-deprived locations, ORC turbines require substantially less water than do conventional STGs. However, to date, ORCs have been applied only in relatively low-power situations.

An option to increase the reliability of power production for parabolic trough and power tower technologies is to use some form of energy storage. Many energy storage technologies exist; examples include storage as chemical energy in storage batteries (a chemical or galvanic battery) or as potential energy in compressed air (a pneumatic battery). However, these energy storage options are impractical and/or inefficient for adaptation to CSP facilities. TES options are technically feasible and efficient additions to parabolic trough and power tower CSP facilities. TES has been demonstrated in power towers (see Section F.2.3 on Solar One and Solar Two) and is currently being built into the Andasol 1 plant in Spain.[7] TES is also a feature of the proposed Ivanpah Solar Electric Generating System (ISEGS) power tower proposed for construction in California (see Section F.2.3.2). Because solar dish engine systems do not produce steam, they cannot be easily hybridized with TES, but unique adaptations are nevertheless currently being studied. Adding TES capabilities allows a portion of the heat generated during periods of greatest insolation to be diverted to storage for later use rather than being used immediately to produce electricity.[8] Simple sodium and potassium nitrate salts with high heat capacities have been found to act as excellent heat storage media. While TES capability is technically feasible, the unresolved issue is whether TES can be implemented cost effectively in a utility-scale CSP facility. Details about TES applications to solar facilities are provided in Section F.2.4.3.

F.2.2 Parabolic Trough Technologies

As noted above, parabolic trough CSP systems are the furthest along toward commercial application of any of the CSP technologies. There are numerous examples worldwide of operating commercial, utility-scale parabolic trough systems as well as numerous facilities proposed or in the design phase. A number of feasibility studies and component evaluation testing initiatives have been completed, and component and system performance assessments have been published on the basis of field experience. Although many engineering designs and performance issues have been settled, many others are still in need of further study and development, all for the purpose of improving the operability, reliability, and overall efficiency of parabolic trough technologies.

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7 See http://www.nrel.gov/csp/troughnet/pdfs/2007/martin_andasol_pictures_storage.pdf for details.

8 In many parts of the country (including the six-state study area of this PEIS), the daily peaks of electric demand occur in the early morning and early evening. In those circumstances, storage heat energy generated in the middle of the day when the sun's energy is most intense effectively allows a CSP facility to produce its greatest amounts of power over periods that coincide with those anticipated power load peaks.

F.2.2.1 Facility Components

F.2.2.1.1 Solar Field (Collectors, Mirrors, and Receivers). The distinguishing feature of parabolic trough systems is the solar field with its parabolically shaped collectors. Parabolic troughs utilize only sunlight's DNI or beam radiation; they do not use diffuse radiation. The optimum size of the solar field is determined by the strength of the DNI incident on the facility's location and the collective optical and thermal efficiencies of the collectors, mirrors, and receivers. Major components in the solar field include:

- Parabolically shaped linear collectors;
- Single-axis tracking structures; and
- Mirrors that collect, reflect, and concentrate the sun's energy at the linear receivers (absorber tubes) (see Figure F.2.2-1).

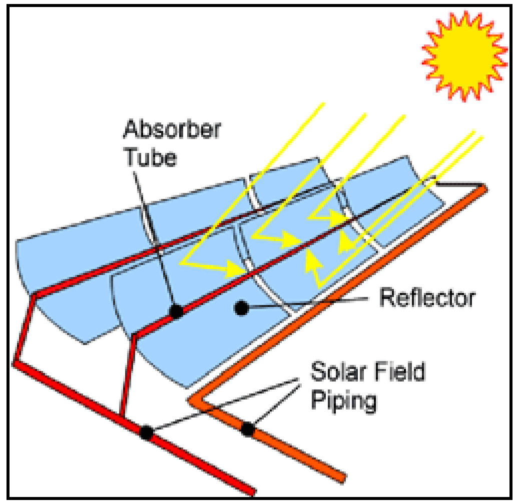

FIGURE F.2.2-1 Parabolic Trough Solar Collector Assembly (Source: NREL. Available at http://www.nrel.gov/csp/troughnet/solar_field.html. Accessed Sept. 4, 2008)

The collectors are structures to which the reflecting surfaces are attached, together with the apparatus that rotates the mirrors to maintain alignment with the sun.

Three basic collector designs have emerged: the Luz system, the Euro Trough, and the Solargenix system. The Luz system and its direct derivative, the Euro Trough, are constructed of galvanized steel and use torsion bars to maintain sufficient structural stiffness to oppose dynamic wind loading while maintaining alignment accuracy. The Solargenix system's support is constructed of aluminum and uses a lighter space frame design that is easier to erect and needs little to no alignment in the field.

The most efficient use of space typically consists of connecting individual collectors in north-to-south-oriented rows and allowing them to track the sun from east to west over the course of a day (Figure F.2.2-2). Sufficient space is left between the rows to allow for maintenance access and to prevent one row of collectors from shading the adjacent row during periods of low sun angles of incidence (at the beginning and end of each day).

The reflecting surfaces (the mirrors) in the solar field have traditionally been manufactured of low-iron, high-transmissivity silvered glass. More recent designs have involved laminated mirrors composed of thinner glass and formed to the parabolic shape of a collector's superstructure. To reduce production costs, rather than incorporating the parabolic shape of the mirror in one piece, collectors are made up of many small flat-plane mirrors, each specifically aligned to reflect light to the parabola's focus.

FIGURE F.2.2-2 Solar Field for the Florida Power and Light Parabolic Trough Facility Known as SEGS VI, Kramer Junction, California (In addition to CSP, the facility also includes a natural gas–fired turbine located in the facility's power block; see background right.) (Source: NREL. Available at http://www.nrel.gov/csp/troughnet/pdfs/32282.pdf. Accessed June 16, 2008)

The receiver (also sometimes called the absorber or the heat collection element [HCE]) is the tube positioned at the focus of each parabolic collector. A stainless steel tube containing the HTF is encased in a glass tube, and the annular space is maintained in a vacuum. To improve its thermal insulating properties, the steel tube is coated with "cermet," a surface treatment consisting of fine metal particles encased in a dielectric ceramic matrix that has a high absorptivity to solar energy and a low emissivity for the infrared spectrum to reduce thermal radiation losses from the receiver. The glass tube is typically constructed of low-iron glass and coated with an antireflection coating to maximize sunlight transmissivity and minimize reflective losses. The receivers of individual parabolic collectors are connected to receivers of adjacent collectors by means of flexible bellows, accommodating the differential thermal expansion between the glass envelopes and the steel tubes and allowing each collector and its receiver to move independently of adjacent collectors and receivers to remain precisely aligned with the sun.

The balance of system components for the solar field includes the collector foundations, tracking and alignment drive systems, and controllers. Given the latitudes at which utility-scale parabolic trough systems are likely to be located, ground freezing is typically not a major concern, so foundation designs are driven primarily by the weight and dynamic wind loading of each panel and the structural properties of indigenous soils and subsoils. Parabolic trough systems use both electric motor and simple gear assemblies or hydraulics for tracking and alignment. Future designs may utilize either system. An individual controller that can be monitored remotely is integrated into a facility-wide supervisory control and data acquisition (SCADA) system. This device controls the tracking and alignment of each collector and monitors the condition of the vacuum and HTF levels in the receiver. However, it is likely that there would be an operating crew present at future utility-scale facilities, especially those located in remote locations.

F.2.2.1.2 Heat Transfer Fluids. All parabolic trough facilities designed and built in the United States have used an HTF to absorb heat from the collectors in the solar field and transfer it to a conventional steam heat exchanger.[9] Ideal HTF properties for solar energy applications are as follows:

- Thermal stability for extended periods of time at high temperatures (HTFs can be heated in the solar field to temperatures >750°F [400°C]);

- Eutectic point (the temperature at which both constituents simultaneously begin to solidify) is below the expected lowest ambient temperature at the facility location [ideally below 32°F (0°C)];

- Low vapor pressure (<1 atmosphere) and low viscosity at the maximum working temperature;[10]

- High heat capacity (the amount of heat energy required to raise the temperature of a specified volume by a specified interval, usually defined by convention as 1 gram of material raised 1 Centigrade degree);

- Little or no potential for thermal decomposition over extended periods of time (especially for organic HTFs);

- Compatibility with HTF containment and recirculation component materials; and

- Relatively low cost.

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[9] Some research has been completed in Europe involving the direct production of steam by circulating a water/glycol mixture, rather than conventional synthetic oil HTF, through the HCEs (Valenzuela et al. 2004; Eck and Steinmann 2002; Zarza et al. 2002). Such a system would be less expensive to construct and simpler to operate since the steam heat exchanger is eliminated. However, although the system could be designed to produce superheated steam, providing even steam flow to the STG would be difficult during periods of fluctuating solar insolation (e.g., from passing clouds). No direct steam generation facilities are currently being studied or have been proposed for the United States; consequently, this option is not discussed further. However, a variation of the conventional parabolic trough system, the CLFR, does produce steam directly at the solar field. See Section F.2.2.2.1.

[10] Low vapor pressure simplifies the design of storage and transfer equipment because it means that high temperature fluids are maintained at relatively low pressures. Because the fluid must circulate, low viscosity reduces the power required to accomplish that.

The material that has been used exclusively to date is a formulation of synthetic organic oils, sold commercially as Dowtherm A®, manufactured by Dow Chemical, or Therminol® VP1, distributed by Solutia, Inc. Both products are mixtures of diphenyl oxide (≈ 73.5%) and biphenyl (≈ 26.5%). Both formulations have been used successfully in CSP plants for many years. The mixture is ideal for CSP applications in regions with high insolation. However, over time (i.e., within the typical facility's 30- to 40-year design basis lifetime), the material has been shown to thermally decompose to produce hydrogen and other organic species such as benzene and dibenzofuran (Moens and Blake 2008). The hydrogen that forms has also been shown to permeate the stainless steel tube containing the HTF and move into the evacuated annular space between the stainless steel tube and the glass outer tube, thus reducing the thermal efficiency of the HCE. Consequently, it is necessary to either capture the hydrogen in special chemical sponges placed in the annular space or provide for the venting of hydrogen from the HTF as it is formed. Venting is typically selected as the simplest strategy for preserving the performance of the HCE and the HTF over the long term. Experience suggests that the extent of thermal decomposition of the HTF is minimal, and replacing the entire volume of HTF within the operating lifetime of a facility is not expected to be necessary.

Although commercial formulations of synthetic oils have predominated as HTFs in solar facilities, they have intrinsic drawbacks that could make them obsolete for application in advanced CSP technologies. Advanced CSP designs that provide higher degrees of solar concentration and function at higher operating temperatures may require alternative HTFs. Substantial research is ongoing to identify those alternatives. Organic salts, compounds composed of organic cations, and organic or inorganic anions that are liquids at expected ambient temperatures are all being investigated. Imidazolium salts have received the most attention (Moens et al. 2003). To date, research has established the effectiveness of imidazolium salts to temperatures of 570°F (300°C); however, some salts exhibited corrosive actions on system components. Mineral oils (paraffinic hydrocarbons) with operating temperature ranges from 14°F to 570°F (–10°C to 300°C) and silicone oils with operating temperature ranges from -40°F to 752°F (–40°C to 400°C) have also been investigated. Both have drawbacks: both can be made to burn, and silicone oils are expensive to produce. The same general physical and chemical properties desirable for HTFs also define excellent thermal storage media. Consequently, mixtures of inorganic nitrate salts similar to those now being used for long-term TES in some CSP facilities are also being considered as HTFs (Moens and Blake 2005). Current research direction appears to suggest that future CSP facilities may use the same material for both initial heat transfer from the solar field and long-term thermal storage. See Section F.2.4.3 for more details on thermal storage options.

Finally, although the choice of both HTF and TES media is based primarily on performance, the selection also involves cost, safety, and environmental considerations. Large, utility-scale CSP facilities with long-term TES capability can be expected to have substantial quantities of HTF and/or TES material present in their respective systems (hundreds of thousands of gallons or more). Consequently, failures of those systems can lead to accidental releases or fires.[11]

F.2.2.2 Utility-Scale Parabolic Trough Facilities

The parabolic trough is the CSP technology with the greatest amount of field experience. Some of the first parabolic trough facilities in the world built to produce electricity are the Solar Energy Generating Systems (SEGS) I through IX facilities installed in three locations in the southern Mojave Desert in Southern California from 1985 through 1991.[12] The plants have a collective capacity of 354 MW and cover 1,600 acres (6.5 km^2). The five SEGS plants constructed at Kramer Junction, California, share some common central ancillary power production, steam cooling, and power plant management facilities. All the SEGS plants utilize Luz-style collectors and support Rankine cycle STGs.[13] SEGS I has a 3-hour TES capability. SEGS II through VII augment heat provided to the steam heat exchanger from the parabolic troughs with heat produced in a natural gas-fired boiler, while SEGS VIII and IX maintain a minimum temperature of HTF during plant downtime by means of a natural gas-fired heater as a way to facilitate (and shorten) cold start-up. Details on the SEGS plants are provided in Table F.2.2-1. The SEGS plants represent a relatively narrow range of Rankine cycle turbine capacities, from 13.5 MWe (gross) in SEGS I to a maximum of 89 MWe (gross)[14] in SEGS VIII and IX.

The Nevada Solar One facility is a parabolic trough plant that has been in operation since June 2007 (Acciona SA 2008). It is located about 40 mi southeast of Las Vegas and has a total facility size of 400 acres (1.6 km^2) (the solar fields encompass 300 acres [1.2 km^2]). Solar One has a maximum capacity of 75 MW and employs about 28 full-time workers during operations. The construction period for the facility was about 16 months. The power produced at the facility is delivered to the electric transmission grid and is sold to the Nevada Power Company and Sierra Pacific Power Company through long-term power purchase agreements.

The simplest configuration for a parabolic trough facility is one in which energy captured in the solar array is used only to produce electricity. It typically includes only the solar field and a conventional STG, together with necessary ancillary support equipment for each. The Beacon Solar Energy Project (BSEP), proposed to be constructed on approximately 2,012 acres (8.14 km^2) in eastern Kern County, California, represents such a “solar only” facility

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[11] Fires are possible not only because of the presence of fluids that burn, but also because the materials are maintained at extreme temperatures and their contact with common combustible materials can result in spontaneous ignition of those materials.

[12] Parabolic trough facilities constructed as early as the mid- to late-1970s were originally built to provide industrial process steam rather than electricity.

[13] The Rankine cycle turbine is the type most commonly used in simple cycle thermoelectric plants that produce steam from the combustion of fossil fuels and is the likely choice for solar thermal applications.

[14] The maximum net power outputs of SEGS VIII and IX were limited by Federal Energy Regulatory Commission (FERC) and Public Utility Regulatory Policy Act (PURPA) requirements.

TABLE F.2.2-1 Solar Energy Generating System (SEGS) Parabolic Trough Plants

Plant Name	Location (California)	First Year of Operation	Net Output (MWe)	Solar Field Outlet Temperature (ºF/°C)	Solar Field Area (acres/km^2)	Efficiency (%)		Annual Output (MWh)	Hybrid Assist
						Solar Turbine	Fossil Fuel Turbine		
SEGS IX	Harper Lake	1991	80	734/390	120/0.49	37.6	37.6	256,125	HTF heater
SEGS VIII	Harper Lake	1990	80	734/390	115/0.47	37.6	37.6	252,750	HTF heater
SEGS VI	Kramer Junction	1989	30	734/390	47/0.19	37.5	39.5	90,850	Gas boiler
SEGS VII	Kramer Junction	1989	30	734/390	48/0.20	37.5	39.5	92,646	Gas boiler
SEGS V	Kramer Junction	1988	30	660/349	62/0.25	30.6	37.4	91,820	Gas boiler
SEGS III	Kramer Junction	1987	30	660/349	57/0.23	30.6	37.4	92,780	Gas boiler
SEGS IV	Kramer Junction	1987	30	660/349	57/0.23	30.6	37.4	92,780	Gas boiler
SEGS II	Daggett	1986	30	601/316	47/0.19	29.4	37.3	80,500	Gas boiler
SEGS I	Daggett	1985	13.8	585/307	21/0.08	31.5	None	30,100	3-h TES

Sources: NREL TroughNet Parabolic Trough Solar Power Network Web site (http://www.nrel.gov/csp/troughnet/power_plant_data.html#solar_one, accessed May 28, 2008) and SDRREG (2005).

(Beacon Solar, LLC 2008). The BSEP will produce power by using only the heat generated in the solar field, except for brief periods of cold start-up when two natural gas boilers will be operated. This facility will have a nominal electrical output of 250 MWe. An Application for Certification (AFC) for the BSEP was filed with the California Energy Commission (CEC) on March 14, 2008, and accepted as complete by CEC on May 5, 2008.[15] Commercial operation is planned to begin in late 2011. The CEC released its Final Staff Assessment (FSA) on October 22, 2009. The FSA is an evaluation of the BSEP application that presents the commission's analysis and recommendations. In its application, Beacon Solar proposed a wet-cooling system that would draw its water from fresh groundwater on-site wells, which is

[15] The complete AFC for BSEP is available electronically at http://www.energy.ca.gov/sitingcases/beacon/index.html. Accessed Jan. 5, 2009.

inconsistent with the State Water Resources Control Board and CEC water policies. The CEC is concerned with the water usage and its source and suggested alternatives for Beacon's consideration. Alternatives include a shift to dry cooling or a different water source that uses degraded groundwater from off-site wells. Beacon Solar continued to support wet cooling, but agreed to use degraded water for its cooling system. In a status conference call on December 1, 2009, BSEP discussed its analysis of three different possible water use plans. However, BSEP continued to propose use of approximately 200 ac-ft/yr (247,000 m^3/yr) of fresh groundwater for processes including mirror washing and emergency usage. On January 12, 2010, CEC released a Proposed Conditions of Certification, which would allow 8 ac-ft/yr (9,870 m^3/yr) of on-site groundwater for potable water needs and 47 ac-ft/yr (58,000 m^3/yr) for emergency purposes. As of January 2010, the CEC had not approved the project's water source for construction and operations water needs, and the water source for BSEP remained unresolved (CEC 2009a).

Future utility-scale CSP facilities may also be hybrids that combine CSP technologies with conventional fossil fuel generation, including integrated solar combined-cycle (ISCC) systems, or even with energy generation technologies that use other renewable fuels, such as biomass. Section F.2.4.4 discusses the feasibilities of such hybrid systems and provides some examples of recently proposed hybrid systems. The environmental impacts of the fossil fuel–fired portions of such combinations are not evaluated in this PEIS.

F.2.2.2.1 Compact Linear Fresnel Reflector (CLFR). While the majority of feasibility studies and technology research, development, and demonstration (RD&D) for CSP focuses on improving overall efficiency through higher operating temperatures and improved dispatchability and reliability of the power being produced, one relatively new CSP technology approach involves changing the fundamental way in which the sunlight is captured and concentrated and its heat applied. Recent technology developments in both Germany and Australia have incorporated the use of a series of nearly flat reflecting surfaces aligned in a parallel arrangement to concentrate sunlight onto an insulated pipe containing water rather than conventional HTF, resulting in the direct production of steam (Figure F.2.2-3).[16]

Apart from the unique concentrating mechanism and the use of water in the HCE rather than conventional HTF, the remainder of the CLFR facility is the same as a conventional parabolic trough facility. CLFR-designed CSP plants offer the following advantages over conventional parabolic trough plants:

- CLFR reflecting mirrors are generally inexpensive to manufacture, and because the focal lengths of the mirrors used in CLFR plants are relatively small, the optical precision need not be as great as is needed for the comparatively more expensive parabolic mirrors.

[16] This technology earns its name from the fact that the parallel arrangement of reflectors behave very much like a Fresnel lens. See Section F.3.2.2 for discussions on a PV technology that employs a Fresnel-type concentrating lens.

FIGURE F.2.2-3 Compact Linear Fresnel Reflector (Source: DOE 2009)

- The nearly flat-plate reflectors in a CLFR plant offer numerous advantages, including:
  - Lower production costs over parabolically shaped reflectors because of less stringent curvature requirements;
  - Simplified installation and sun tracking; and
  - Reduced shadow interference between adjacent reflectors, allowing for closer spacing and, attaining equivalent solar heat capture in a smaller footprint, thus minimizing land use.

- Single-axis tracking of the mirrors simplifies design and deployment as well as maintenance.

- Wind loading issues are reduced due to the comparatively lower profile than conventional parabolic troughs.

- The direct production of steam simplifies plant design and reduces both capital and operation and maintenance (O&M) costs (through elimination of the HTF circulation and storage components) and allows for more rapid plant start-up

Once the steam is produced, downstream activities, as well as equipment associated with power generation and steam condensate management and recycling, are essentially the same as for other parabolic trough facilities. Many aspects of CLFR technology are still under development. If the anticipated reduced costs can offset the reductions in performance over a trough collector and if CLFR facilities can operate at temperatures as high as 734°F (390°C), as does a conventional trough plant, they are likely to find a potential market in utility-scale power production.

No CLFR facilities were operating in the United States as of February 2010. Ausra CA II, LLC (doing business as Carrizo Energy, LLC) recently submitted an AFC to the CEC (Carrizo Energy, LLC 2007) for what would have been the first operating utility-scale CLFR facility–the Carrizo Energy Solar Farm (CESF), in San Luis Obispo County, California.[17] The proposed project was terminated in November 2009, but the application data is still assumed to be generally representative of this category of CSP technology.

F.2.2.2.2 Non-Steam-Based Power Turbine Options. Most CSP technologies utilizing a steam cycle have incorporated the use of conventional steam-driven turbines. However, some non-steam-based turbine options also exist. The Saguaro Solar Power Plant, a 1-MWe parabolic trough facility owned by Arizona Public Service, is currently operating in Red Rock, Arizona, using an ORC turbine-generator (Figure F.2.2-4).[18] Pentane rather than water is used as the working fluid in the Saguaro ORC. Spent pentane exiting the turbine is condensed and cooled with the use of a completely closed-loop, glycol-based water coolant heat exchanger. Other than the initial filling of the system with water-based coolant (which must be replaced periodically to control internal corrosion), the Saguaro facility consumes no water to produce electricity.

Various organic compounds can be used as HTFs in ORC turbines. Because of the relatively low boiling point [97ºF (36ºC)] of pentane, the Saguaro ORC turbine operates at relatively low temperatures compared to conventional steam turbines. However, pentane is also extremely flammable and has a relatively low autoignition temperature of 500ºF (260ºC), so its use introduces some fire risk. Selection of HTFs with higher boiling points and heat capacities relative to pentane but with less extreme (or no) flammability characteristics (e.g., synthetic oils or hydrofluorocarbon or perfluorocarbon commercial refrigerants) would allow for designs of ORC turbines with significantly higher power-generating capacities, along with reductions of concomitant risks from the working fluid. However, some alternative working fluids, while nonflammable, still have significant ozone depletion potential, although such would not be of environmental consequence unless the working fluid system developed a leak.

Field experience with ORC turbines in solar thermal power plants is limited, and ORC turbines have been used only in facilities with relatively small power outputs. Nevertheless, the Saguaro facility clearly demonstrates the technical applicability of ORC turbines at parabolic trough and power tower facilities. However, despite the intrinsic benefits of ORC turbines in arid

[17] The complete AFC for the CESF, as well as other documents related to the CEC review, are available at http://www.energy.ca.gov/sitingcases/carrizo/documents/index.html. Accessed Jan. 5, 2009.

[18] For details about the Saguaro Solar Power Plant, go to http://www.renewableenergyworld.com/rea/news/story?id=44696 and http://www.aps.com/_files/renewable/SP017SaguaroSolarTrough.pdf. Accessed Jan. 5, 2009.

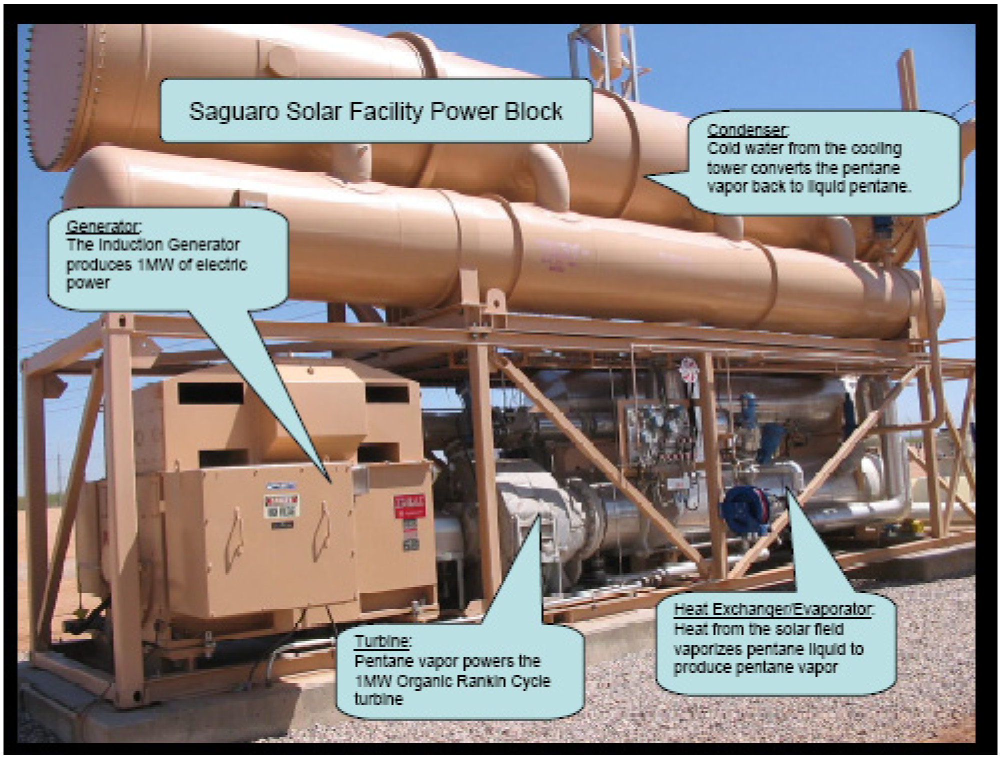

FIGURE F.2.2-4 Power Block of the Saguaro Solar Facility Showing a 1-MWe Pentane Organic Rankine Cycle Turbine (Courtesy of Arizona Public Service. Reprinted with permission. Available at http://www.aps.com/_files/renewable/SaguaroSolarFacilityPowerBlock.pdf. Accessed Aug. 6, 2008)

environments where cooling water is scarce, their limited application to date in utility-scale solar facilities as well as the lack of their inclusion in recently proposed facilities would appear to indicate that ORC turbines will likely not predominate or even come into widespread use in utility-scale solar facilities in the near term.

F.2.2.3 Optimizing the Size and Design of Parabolic Trough Facilities

Various RD&D initiatives addressing all aspects of parabolic-trough facility design and operation are complete or under way. The quality of the solar resource continues to be the largest determinant of overall CSP facility performance and the levelized cost of energy (LCOE)[19] that it can provide. Nevertheless, improvements in individual components that will also contribute to overall improved performance are contemplated. Using the SEGS VI plant as a baseline reference, the San Diego Regional Renewable Energy Group (SDRREG) anticipates the following changes in individual component efficiencies or plant parameters for plants built in 2012 (SDRREG 2005):

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[19] Levelized cost of energy (also sometimes called the levelized cost of electricity) is the cost of the energy-generating system including all of the costs over its lifetime (initial investment, O&M, cost of fuel, and cost of capital).

- Optical efficiency increase from 53.3% to 72%;

- Receiver thermal efficiency increase from 72.9% to 86.3%;

- Piping thermal efficiency increase from 96.1% to 97.0%;

- Storage thermal efficiency increase from 99.4% to 99.7%[20];

- Power plant efficiency increase from 35% to 39.2%;

- Electric parasitic load increase from 82.7% to 92.9%;

- Power plant availability decrease from 98% to 94%; and

- Annual solar-to-electric efficiency increase from 10.6% to 17.1%.

Although data from the SEGS plants (see Section F.2.2.2) provide valuable field experience for virtually all aspects of parabolic trough facility design and operation, they do not define the ideal parabolic trough plant size and configuration.[21] Many configurations and sizes of parabolic trough facilities are possible. A study commissioned by the U.S. Department of Energy's (DOE's) NREL explored the advantages, disadvantages, and probable configurations of large-scale parabolic trough power plants in an effort to approximate the most preferred size and configuration (Kelly 2006a). The study sought to identify the preferred plant size, that is, those engineering dimensions and power-producing capacities that represent a favorable balance among maximum capture of economies of scale, parasitic losses, and capital and operational costs such that overall system efficiencies and economies are realized and the LCOE produced is minimized.

Using utility- and industry-accepted models and parameters and published performance characteristics of major components, Kelly (2006a) determined the preferred sizes for parabolic trough facilities with and without TES. The major parameters evaluated in that study included Rankine cycle STG frame sizes and performance characteristics,[22] steam conditions, steam feedwater system, solar field size and geometries, HTF pumping costs and pressure losses, TES systems, steam cooling systems, and other parasitic losses associated with fluid transfers (HTF, steam/condensate, cooling water [in wet recirculating systems—see Section F.2.4.2], and molten salt [in TES systems—see Section F.2.4.3]), land acquisition and labor costs, as well as capital and operational costs. Major conclusions of the study include the following:

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[20] Solar VI did not have thermal storage. Instead, the reference case is a hypothetical parabolic trough with 6-hour TES using 2007-era technologies.

[21] The ideal plant size and configuration is one that captures the maximum economies of scale for all components and aspects of plant operation while minimizing construction and operation/maintenance costs and parasitic losses (auxiliary loads that must be subtracted from the gross plant output).

[22] STGs are available in discrete frame sizes, with the number of stages, turbine blade lengths, and inlet and outlet steam pressures dictating the power-production capacity of available variants within each frame size.

- For parabolic trough plants using Therminol HTF with molten salt TES, a capacity of 200 MWe is likely to be the upper limit for the most economic plant. Multiple equipment items for the HTF and TES systems for larger plants, as well as the Rankine cycle STGs approaching their maximum efficiency of 38%, argue against any further increases in plant size.

- For parabolic trough plants using Therminol HTF without TES, the largest economical plant size is 250 MWe. At this plant size, HTF system efficiencies are maximized, and Rankine cycle STGs have attained their highest efficiencies.[23]

While the Kelly (2006a) study did not specifically evaluate plants that use inorganic HTFs in place of synthetic oils, the author notes that because inorganic salt HTFs allow the solar field to operate at higher temperatures, the maximum plant size would likely be in the range of 250 MWe to 300 MWe for plants with TES and 350 MWe for plants without TES.

A study published by SDRREG (2005)[24] demonstrated important design relationships for components of parabolic trough facilities utilizing TES: provided that a large enough solar field is selected and that the ideal ratio of solar multiple to hours of TES capacity is maintained, designers can create facilities with varying TES capacities while maintaining a competitive LCOE. This conclusion provides important flexibility in establishing Power Purchase Agreements (PPAs) that guarantee that the solar facility can produce power during periods of peak demand in the load centers it supports, regardless of whether those periods coincide with the times of maximum DNI. Figure F.2.2-5 demonstrates the relationships between LCOE, hours of TES, and the solar multiple of a hypothetical plant.[25,26] However, it is also important to note that CSP facilities with TES capability are able to produce power during peak loads, irrespective of insolation over those periods. This makes that power more valuable to transmission system operators and may result in a somewhat higher cost of electricity for consumers.

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[23] Importantly, the maximum sizes of 200 MWe and 250 MWe for plants with and without TES, respectively, do not reflect the dispatchability of either plant. So, while the maximum preferred size of a parabolic trough plant with TES is less, its dispatchability, and thus its value as a source of power to the grid, is significantly greater than that of the plant without TES.

[24] An appendix to this study, from which the data cited below were derived, was produced by NREL.

[25] The solar multiple reflects the ratio of the size and heat-generating capacity of the solar field to the amount of heat needed for the facility to operate at its peak power rating. A facility with a solar field only large enough to supply the amount of heat needed to produce steam and generate power at the facility's peak power rating is said to have a solar multiple of 1.0. If the solar field of such a facility were expanded to double its heat-producing capacity, the facility would have a solar multiple of 2.0. Such "excess" heat could then be directed to TES applications and used at a later time to produce steam and power. As a practical matter, most CSP plants would be designed with solar multiples greater than 1.0 even when no TES features were present. This would allow a portion of the solar field to be taken out of service for maintenance or repair without compromising the facility's ability to deliver power at its nameplate power rating.

[26] The values represented in Figure F.2.2-5 were derived by using the NREL Solar Advisor model. Details on that model are available at https://www.nrel.gov/analysis/sam/download.html. Accessed Jan. 5, 2009.

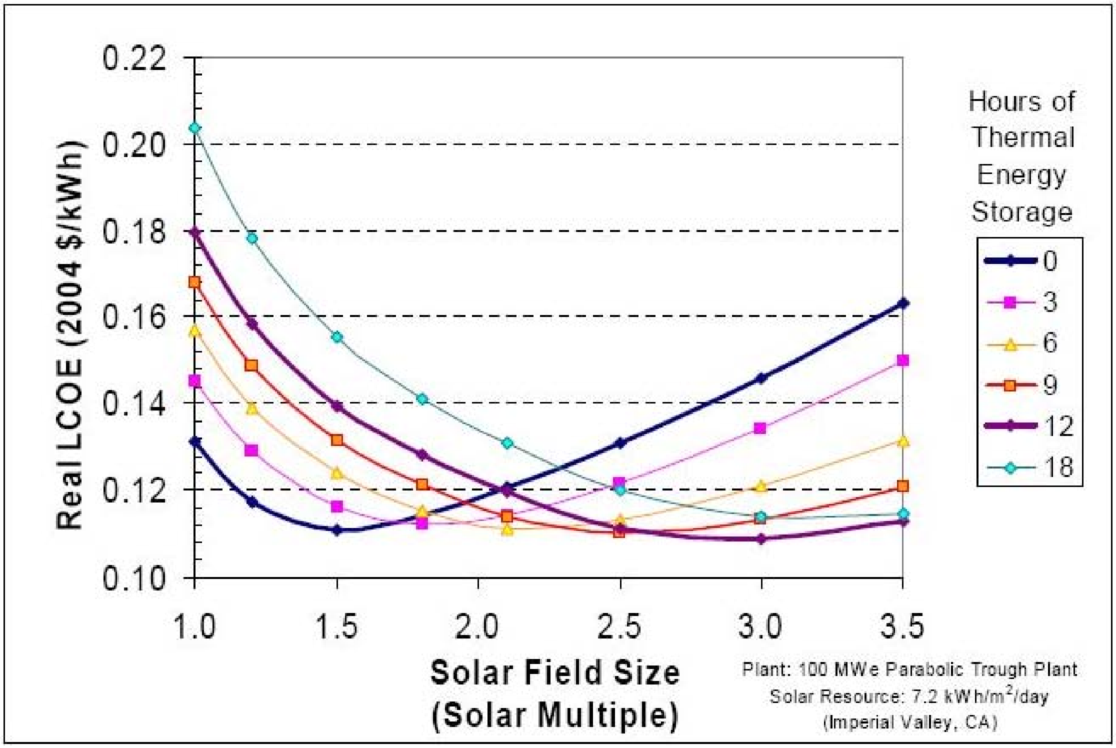

FIGURE F.2.2-5 Relationship between Solar Multiple and Levelized Cost of Energy for Parabolic Trough Facilities with Various TES Capacities (Source: NREL, as cited in SDRREG 2005)

Another parameter that can be used in defining an optimal parabolic trough plant configuration is the facility's capacity factor, or the percentage of time that the plant can produce power at its design basis. Here, again, the facility's solar multiple and TES capacity together play critical roles, offering designers flexibility in maximizing the capacity factor of a parabolic trough plant. The SDDREG study also explored the relationships among solar multiple, TES, and capacity factor. The results of that analysis are shown in Figure F.2.2-6.[27] As shown in that figure, a facility with a solar multiple of 3.5 and a TES capacity of 18 hours can provide nameplate levels of power more than 60% of the time. Increasing the capacity factor greatly improves the value of the solar plant as a source of reliable and dispatchable grid-connected power. However, increases in both the solar field size and TES capacity required to accomplish that will increase capital and O&M costs.

[27] As with the values in Figure F.2.2-5, the values in Figure F.2.2-6 were derived using the NREL Solar Advisor Model. The model is available at https://www.nrel.gov/analysis/sam/download.html. Accessed Jan. 5, 2009.

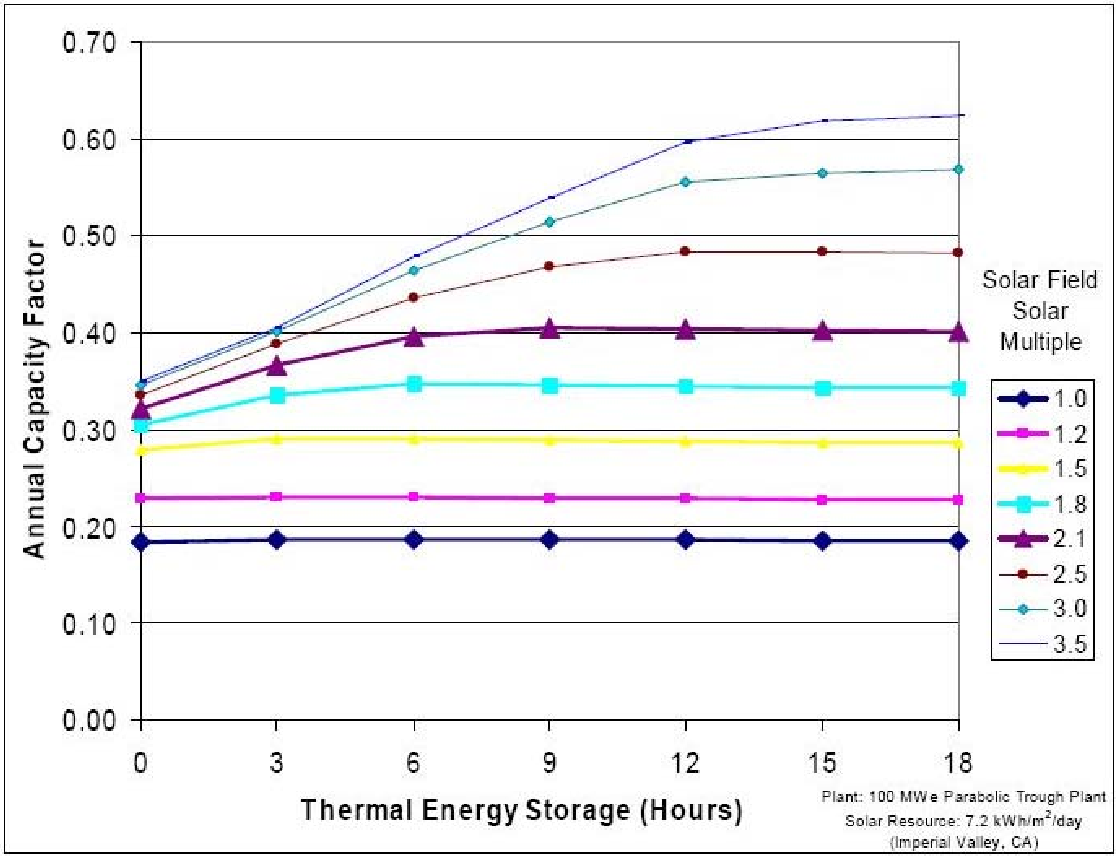

FIGURE F.2.2-6 Relationships among Solar Multiple, TES, and Capacity Factor for Parabolic Trough Facilities (Source: NREL, as cited in SDRREG 2005)

F.2.2.4 Engineering Parameters and Resource Requirements for Parabolic Trough Facilities

To support an environmental impact analysis of utility-scale parabolic trough facilities, it is necessary to define representative engineering parameters and resource requirements. This section presents these data for (1) a typical 250-MWe parabolic trough facility with 3 hours of TES,[28] (2) a proposed 250-MWe "solar only" parabolic trough facility, and (3) a proposed 177-MWe CLFR facility. These data are considered representative of similarly sized utility-scale parabolic trough facilities, although they may not anticipate parameters and requirements for future proposed facilities.

Engineering parameters for a hypothetical 250-MWe parabolic trough facility with TES were estimated by Kelly (2006a). Those parameters and dimensions that most directly relate to environmental impact are presented in Table F.2.2-2.

[28] Section F.2.4.3 provides a detailed description of various TES options.

TABLE F.2.2-2 Critical Parameters of a Hypothetical 250-MWe Parabolic Trough Facility with 3-Hour TES

Parameter	Quantity	Notes
Structures and Improvements		
Clear and grub	1,048 acres (4.2 km^2)	Applies to the entire facility
Excavations (site-wide)	38,487 yd^3 (29,443 m^3)	Foundations, footings, buried piping, and controls
Backfill and compaction (site-wide)	11,762 yd^3 (8,998 m^3)	Foundations, footings, buried piping, and controls
On-site roads—grading	25,600 yd^2 (21,427 m^2)	Does not include access road(s)
On-site roads—8-in. base	4,200 yd^3 (3,213 m^3)	Does not include access road(s)
On-site roads—3-in. asphalt	16,700 yd^2 (13,978 m^2)	Does not include access road(s)
On-site roads—6-ft shoulders	7,200 yd^2 (6,026 m^2)	Does not include access road(s)
Site perimeter fence	28,500 ft (8,687 m)	Assumed 10-ft chain link
Evaporation pond—grading	49,300 yd^2 (41,264 m^2)	Steam and cooling water blowdown
Evaporation pond—clay lining	36,400 yd^3 (27,846 m^3)	
Maintenance/warehouse building	6,000 ft^2 (558 m^2)	
Control/electrical/administration building	4,000 ft^2 (317 m^2)	
Security/gatehouse	150 ft^2 (14 m^2)	
Nitrogen storage vessel	3	Horizontal, cylindrical tank, 14-ft diameter, 51 ft long
Cold salt storage tank	3	Vertical cylindrical tank, 102-ft diameter × 46-ft height
Hot salt storage tank	3	Vertical cylindrical tank, 104-ft diameter × 46-ft height
Oil-to-salt heat exchangers	24	Straight shell, U-tube, 42,400 ft^2 heat transfer area each
Nitrogen-to-air heat exchanger	1	Finned tube, forced draft heat exchanger 50 ft^2 (4.6 m^2) bare tube area, 650 ft^2 (60.4 m^2) finned tube area, 0.75 brake horsepower (bhp) electric fan
Cold salt pumps	3	Extended shaft turbine pump, 1,750 bhp motor
Hot salt pumps	3	Extended shaft turbine pump, 1,750 bhp motor
Solar field	492 acres (1.99 km^2)	Parabolic troughs
HTF	1,228,000 gal (4,648 m^3)	Solutia Therminol VP-1
Tanks (only major tanks listed)		
Fuel oil storage (diesel emergency generator)	1	5,000 gal (19 m^3), horizontal, double-walled fiberglass, underground
Diesel generator day tank	1	200 gal (0.76 m^3), horizontal, carbon steel Above ground with concrete catch basin
Sludge thickener	1	3,000 gal (11.4 m^3), cone bottom, open top carbon steel with plastic lining and internals, 7-ft, 6-in. diameter × 10-ft high

TABLE F.2.2-2 (Cont.)

Parameter	Quantity	Notes
Tanks (Cont.)		
Sulfuric acid storage	1	6,000 gal (22.7 m^3), horizontal cylindrical, carbon steel 7-ft diameter × 21-ft long
Caustic soda storage	1	3,500 gal, (13.2 m^3) horizontal cylindrical, carbon steel 5-ft diameter × 23 ft, 6 in.
Soda ash storage bin	1	10,000 lb (4,540 kg) capacity, vertical cylindrical
Quick lime storage bin	1	9,600 lb (4,350 kg) capacity, vertical cylindrical
Steam-turbine generator lube oil	1	10,000 gal (37.9 m^3)
Cooling towers	1	Wet, mechanical draft, 135,000 gpm (511 m^3/min) water circulation, 9 cells, 1 fan/cell, 101 to 80°F @ 104°F dry bulb/ 68°F wet bulb

Source: Kelly (2006a).

In comparison, the critical engineering and environmental resource requirements of the proposed 250-MWe "solar only" BSEP facility, described in Section F.2.2.2, include the following (Note: changes to project parameters that occurred as a result of the CEC's FSA [Section F.2.2.2] are reflected in brackets and italics (e.g., *[6 acres]*):

- Power generation and fuel consumption
  - Nominal capacity: 250 MWe (gross)
  - Capacity factor (annual): 26.5%
  - Estimated annual power production: 600,000 MWh/yr
  - Parasitic load: 11%
  - Estimated natural gas consumption: 36,000 MMBtu/yr

- Facility size
  - Total footprint: 2,012 acres (8.1 km^2)
  - Solar array: 1,244 acres (5.0 km^2)
  - Power block: 22 acres (0.09 km^2)

- Solar array
  - Single-axis tracking parabolic trough
  - Total reflected area: >494 acres (>2 km^2)
  - HTF: Therminol™ VP-1
  - HTF temperature: 740°F (394°C)

- Power block and ancillary equipment
  - STG and support equipment (1)
  - Water-cooled condenser (1)
  - Natural gas boilers (2) to aid in cold start-up and prevent freezing of HTF
  - Wet recirculating cooling with mechanical draft cooling tower
  - Emergency fire-water pump engine and diesel fuel tank
  - Diesel-fueled generator for emergency alternating current (AC) power
  - Batteries for emergency direct current (DC) power
  - Evaporation ponds (3), double-lined, 8.3 acres (0.03 km^2) *[2 acres (0.01 km^2)]* each; 25 acres (0.1 km^2) *[6 acres (0.02 km^2)]* total

- Tanks
  - Raw water: 2,840,000 gal (10,751 m^3) (vertical, field erected)
  - Treated water: 2,350,000 gal (8,896 m^3) (vertical, field erected)
  - Demineralized water: 150,000 gal (568 m^3) (vertical, field erected)
  - Sodium hydroxide (steam water treatment): 7,500 gal (28 m^3)
  - Sulfuric acid (steam water treatment): 10,000 gal (38 m^3)
  - Lubricating oil and diesel fuel: various sizes, largest <1,200 gal (4.5 m^3)

- Transmission line: 230 kV, 3.5 mi (5.6 km)

- Water requirements and management
  - Source: off-site groundwater wells *[on-site groundwater wells]*
  - Consumption: average flow, 990 gpm (3.8 m^3/min); peak flow, 4,054 gpm (15.3 m^3/min) *[no update on this parameter was given in the October 2009 FSA]*
  - Zero-discharge evaporation ponds for cooling tower blowdown disposal
  - Estimated consumptive use: 1,600 ac-ft/yr (1.97 million m^3/yr) (1,388 ac-ft/yr [1.71 million m^3/yr])
  - Consumptive uses include wet, recirculating steam cycle cooling, miscellaneous industrial processes, mirror washing, and potable and sanitary uses

- Construction (includes natural gas connector pipeline and transmission line)
  - Project construction period: 25 months
  - Peak construction workforce: 836
  - Average construction workforce: 477

Critical engineering parameters and environmental resource demands for the proposed CLFR CESF facility, described in Section F.2.2.2.1, include the following:

- Nominal capacity: 177 MWe (net); 230-kV interconnect voltage

- Anticipated construction period: 35 months

- Typical operating periods: 13 h/day, 4,765 h/yr

- Overall plant size: 640 acres (2.6 km^2); additional 380-acre (1.5-km^2) construction laydown area

- Buildings and major structures
  - Control/administration building: 3,000 ft^2 (279 m^2), 40 ft (12 m) high
  - STG building: 10,000 ft^2 (930 m^2), 60 ft (18.3 m) high
  - Air-cooled condensers (2): 55,000 ft^2 (5,120 m^2) footprint, 115 ft (35 m) high
  - Water treatment facility: 300 ft^2 (28 m^2), 20 ft (6.1 m) high
  - Warehouse/shop building: 11,250 ft^2 (1,046 m^2), 20 ft (6.1 m) high
  - Fire water pump building: 1,000 ft^2 (93 m^2) by 15 ft (4.6 m) high
  - Blowdown tank (vertical) (29,000 gal [110 m^3]): 12 ft (3.7 m) diameter by 25 ft (7.6 m) high
  - Condensate tank (horizontal) (20, 000 gal [76 m^3]): 10 ft (3.0 m) diameter by 26 ft (7.9 m) long by 20 ft (6.1 m) high
  - Raw fire water tank (vertical) (450,000 gal [1,703 m^3]): 56 ft (17 m) diameter by 28 ft (8.5 m) high
  - Service water tank (vertical) (150,000 gal [568 m^3]): 36 ft (11 m) diameter by 19 ft (5.9 m) high
  - Decimalized water tank (vertical) (40,000 gal [151 m^3]): 17 ft (5.2 m) diameter by 28 ft (8.5 m) high

- Solar field: 618 acres (2.5 km^2)
  - 195 CLFR "lines:" each 90 ft (27.4 m) wide by 1,268 ft (387 m) long by 5 ft (1.5 m) high and each consisting of 10 mirrors reflecting sunlight to a linear Fresnel lens that focuses heat on a stationary steam tube

- Internal roadways: 7 mi (11 km)

- High perimeter fencing: 10 ft (3.0 m)

- Steam production: 2.52 million lb/h (1.14 million kg/h) at 720 psia (49.6 bar)

- Water demands (based on 4,765 h/yr of operation):
  - Average daily water consumption (for various maintenance processes and steam cycles): 18,500 gal (70 m^3)
  - Average annual water consumption: 21.8 ac-ft (26,890 m^3), based on average annual conditions of 95°F (35°C) at 100% load for 4,745 h/yr with mirror washing 250 days/yr
  - All water supplied by on-site well

F.2.3 Solar Power Tower Technologies

Although power tower technology shares many characteristics with parabolic trough technology, it has distinct differences. Parabolic reflectors of a parabolic trough facility act as line concentrators, focusing the sun's heat on a corresponding segment of an HTF-filled tube. All of the power tower's nearly flat plate reflectors[29] (known as heliostats) work collectively as point concentrators, focusing the sun's heat on a central point at the top of a centrally located tower. Two large-scale research and demonstration facilities, the 10-MW Solar One facility near Barstow, California, and Solar Two, a retrofit of Solar One that incorporated molten salt storage, were operated in the United States from 1982 to 1997 and produced more than 38,000 MWh of electricity. Both plants proved the viability of tower technology. Furthermore, Solar Two, which at one point operated continuously at nameplate rating for 7 days, demonstrated the value of molten salt TES when combined with power tower technology to greatly improve the dispatchability of electricity from power towers.

Only one power tower facility with a power capacity of greater than 10 MW is currently operational in the world: PS10 in the Solucar Solar Park in Spain. PS10 consists of a central 377-ft (115-m) tower and 624 heliostats that focus the sun's radiation onto the uppermost part of the tower. Each heliostat has a reflecting surface area of 1,291 ft^2 (120 m^2) for a total reflecting surface area of 807,605 ft^2 (75,000 m^2). The facility has a nameplate rating of 11 MWe using only the solar field to produce steam. That rating can be augmented by as much as 12% to 15% with the introduction of a natural gas boiler to increase steam production. A companion plant, PS20, which has twice the power capacity, was scheduled to be commissioned in 2008.[30]

The heliostats' central point focus is a receiver positioned at the top of a tower that is at the center of an array of heliostats.[31] Depending on the number and positioning of the heliostats and the insolation available, the heat transfer medium at the receiver can be heated to as high as 1,050°F (565.5°C) (see DOE 2009).[32] Once the sun's reflected and concentrated heat is captured, the downstream activities of producing steam and subsequently using that steam in a Rankine cycle STG are essentially identical to those activities in a parabolic trough facility. A conceptual power tower facility with molten salt TES is shown in Figure F.2.3-1. An aerial photograph of the Solar Two facility in Barstow, California, is shown in Figure F.2.3-2.

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29 Heliostats have a slight curvature. The amount of curvature dictates the focal length of the reflector. For power towers, the focal lengths of the reflectors (the distance from the reflector to the point at the top of the tower on which the heliostats are focused) is much greater (on the order of tens or even hundreds of feet) than the focal length of a typical parabolic trough facility, where the focus of the reflector is the HCE, which is only a few feet from the reflecting surface.

30 Details on PS10 and PS20 are available at http://www.abengoasolar.com/sites/solar/en/. Accessed Jan. 5, 2009.

31 Heliostats need not completely surround the tower; however, a recently proposed power tower facility incorporates such a 360° array—see Sections F.2.3.2 and F.2.3.3.

32 This temperature can be attained only in a power tower facility with molten salt TES. Power tower facilities that store heat as steam operate at lower temperatures. For example, the PS10 facility in Spain operates at a steam temperature of 450°F (232°C) (and a pressure of 500 pounds per square inch [psi]).

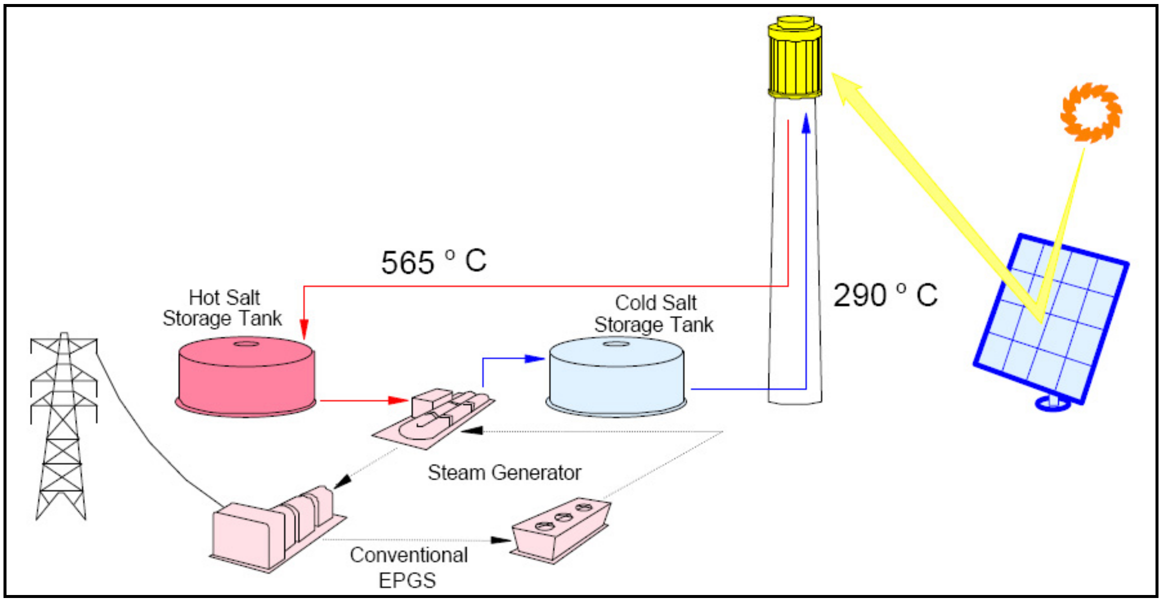

FIGURE F.2.3-1 Schematic of a Power Tower Facility with Two-Tank Molten Salt Storage (Depiction of the Solar Two facility) (Source: Sandia National Laboratory. Available at http://www1.eere.energy.gov/solar/pdfs/kolb.pdf. Accessed June 19, 2008)

F.2.3.1 Facility Components

F.2.3.1.1 Solar Field: Mirrors and Receivers. The solar field of a power tower facility consists of individual slightly curved heliostats capable of single-axis or dual-axis sun tracking and that are aimed at the receiver at the top of the centrally located tower. The receiver is simply a container holding the HTF, which, in the case of the only commercial power tower facility built to date, has been water/steam. However, as discussed above, feasibility studies suggest that a power tower design utilizing a molten salt mixture identical to the medium used for parabolic trough TES (see Sections F.2.3.2 and F.2.3.3) could be used as both an HTF and a TES medium in a power tower. The molten salt would be capable of producing steam immediately or storing heat for later steam production. (See Section F.2.4.3 for additional discussions on TES options.)

F.2.3.1.2 HTFs in Current and Future Power Towers. To date, only water has been used as an HTF in commercial power tower plants. However, because of the high concentrating ratios provided by the numerous heliostats, power tower facilities are nevertheless capable of generating receiver temperatures of more than 1,000°F (537°C). For example, the proposed ISEGS is capable of providing superheated steam at 1,004°F (540°C) and 2,030 psi (140 bar) to its STGs. (See Section F.2.3.2 for details.) Future power towers may use molten salt as both an HTF and a TES medium and may be capable of generating even higher receiver temperatures, allowing for the production of supercritical rather than subcritical steam, which

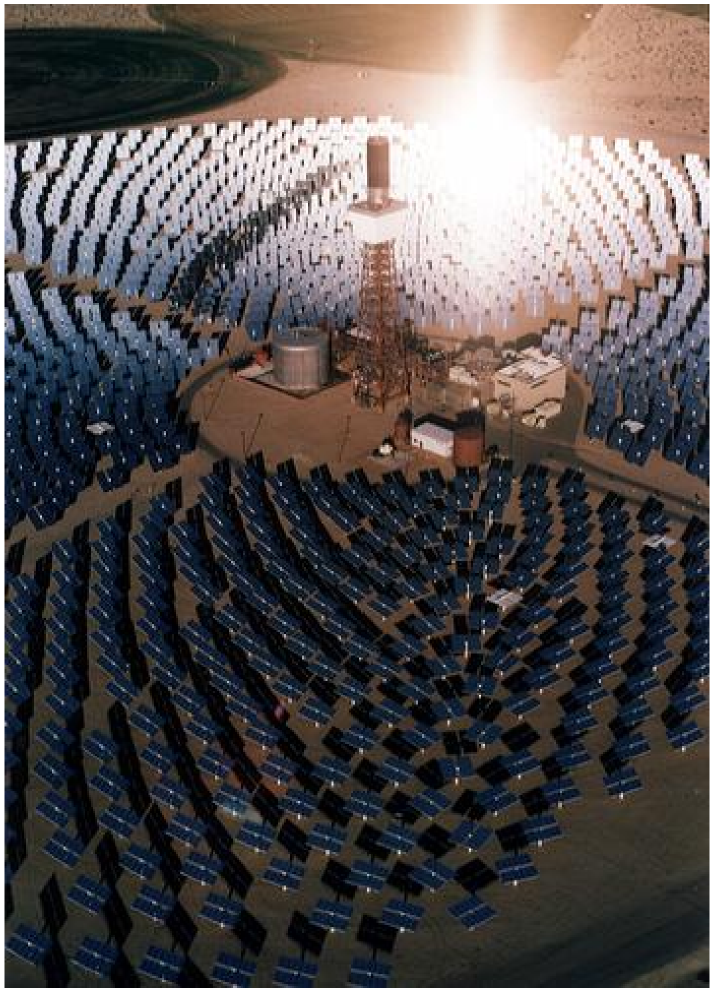

FIGURE F.2.3-2 Solar Two, CSP Power Tower Facility in Daggett, California (Source: NREL Photo #01701. Photo Credit: Sandia National Laboratory. Available at http://www.nrel.gov/data/pix/searchpix.cgi?getrec=10135024&display_type=verbose&search_reverse=1. Accessed July 2, 2008)

would result in higher operating efficiencies for the STGs.[33] However, no actual power tower facilities have been designed to produce supercritical or ultra supercritical steam, and the ISEGS proposes to use water as its HTF and have only 1 hour of TES capability (stored as steam).

[33] "Supercritical" and "subcritical" define the thermodynamic state of the water in the steam cycle. In supercritical steam-generating units, the steam cycle pressure is maintained above water's critical point so that there is no distinction between water's liquid and gaseous phases and the steam behaves as a homogenous supercritical fluid. The supercritical point for water is 22.1 MPa (approximately 3,207 psi). Supercritical steam generators offer numerous advantages over their subcritical counterparts, including higher thermal efficiencies and greater flexibility in changing loads. Finally, ultra supercritical steam-generating plants, operating at steam conditions as high as 4,500 psi and 1,112°F, are operational in Denmark and Japan; however, none is currently operating in the United States.

The use of molten salt HTF would result in special design and operating demands. For example, the circulation pumps would need to be constructed of materials compatible with the salt and would need to be designed to withstand the expected higher operating temperatures. Preventive maintenance to preempt corrosive deterioration of salt management systems, heat tracing on all transfer piping to ensure that the salt's temperature stays above its eutectic point, and supplemental heating during down periods to shorten cold start-up periods might be required, all of which would create an increased parasitic load for the facility.

F.2.3.2 Utility-Scale Power Tower Facilities

As noted above, the ISEGS is a proposed utility-scale power tower facility that, if approved, will be located near the Ivanpah Dry Lake in San Bernardino County, California, on land administered by the U.S. Department of the Interior (DOI) Bureau of Land Management (BLM).[34] An AFC (BrightSource Energy, Inc. 2007) for ISEGS was submitted to the CEC on August 28, 2007, and deemed complete by the CEC on October 31, 2007.[35] The FSA and Draft Environmental Impact Statement (CEC 2009b) was published on November 4, 2009.[36] Project parameters were changed during the CEC's evaluation of the AFC and are reflected in brackets and italics (e.g., *[270 MWe]*) in the requirements listed below. Changes in design optimization were made in response to data requests from CEC to the applicant and mostly include reduction in the number of heliostats, increased heliostat surface area, movement of project boundaries, and reduction in the number of power towers. On February 11, 2010, BrightSource submitted a Biological Mitigation Proposal that would reduce impacts to biological and visual resources. The mitigated ISEGS 3 configuration includes further reduction in the project footprint, number of heliostats, and number of towers. It also results in a capacity reduction to ISGES 3 from a nominal 200 MWe to 170 MWe (CEC 2010).

The ISEGS facility is proposed to be built in three phases. ISEGS 1 and ISEGS 2 will each have a nominal rating of 100 MWe, while ISEGS 3 will be rated at 200 *[170]* MWe, for a total facility capacity of 400 *[370]* MWe. Each phase will be capable of independent operation, and each will be supported by a natural gas boiler that will shorten cold start-up times. Some functions of facility operation will be centralized to support all three ISEGS phases while minimizing the environmental footprint of the facility.

[34] Project approved. Updated information will be included in the Final PEIS.

[35] The complete AFC for the ISEGS, as well as documents related to the CEC review, are available at http://www.energy.ca.gov/sitingcases/ivanpah/documents/index.html. Accessed Jan. 5, 2009.

[36] The complete FSA and Draft Environmental Impacts Statement are available at http://www.energy.ca.gov/2008publications/CEC-700-2008-013/FSA/. Accessed Nov. 20, 2009.

F.2.3.3 Engineering Parameters and Resource Requirements for Power Tower Facilities

To support an environmental impact analysis of utility-scale power tower facilities, it is necessary to define representative engineering parameters and resource requirements. This section presents these data for the proposed ISEGS facility described in Section F.2.3.2. These data are considered to be representative of similarly sized utility-scale power tower facilities, although they may not anticipate parameters and requirements for future proposed facilities.

Salient engineering parameters and environmental resource requirements for the ISEGS facility include the following (Note: changes to project parameters that occurred during the CEC's evaluation of the AFC are reflected in brackets and italics):

- Power ratings
  - ISEGS 1 and ISEGS 2: 100 MWe each *[ISEGS 1: 120 MW; ISEGS 2: 125 MW]*
  - ISEGS 3: 200 MWe *[ISEGS 3: 125 MW]*

- Land area
  - ISEGS 1 and ISEGS 2: 850 acres (3.4 km^2) each *[914 acres (3.7 km^2) and 1,097 acres (3.7 km^2), respectively]*
  - ISEGS 3: 1,660 acres (6.7 km^2) *[1,227 acres (7.4 km^2)]*
  - Total facility (ISEGS 1, 2, and 3 plus shared facilities): 3,400 acres (13.8 km^2) *[3,582 acres (16.5 km^2)]*

- Towers and heliostat arrays
  - Towers: three *[one]* each for ISEGS 1 and 2, four *[one]* for ISEGS 3
  - Tower heights: 312 ft (95 m) for ISEGS 1 and 2, 459 ft (140 m) for ISEGS 3 *[459 ft [140 m] for ISEGS 1, 2 and 3]*
  - Heliostats (each): 7.2 ft (2.2 m) high, 10.5 ft (3.2 m) wide, 75.6-ft^2 (7.04-m^2) reflection surface area (an overall height of 12 ft [3.6 m])
  - Heliostat arrays: 68,000 each for ISEGS 1 and ISEGS 2 *[53,500 for ISEGS 1, 60,000 for ISEGS 2]*, 136,000 *[60,000]* for ISEGS 3

- Air-cooled condensers for each steam cycle

- Natural gas boiler for each tower
  - Used to shorten cold start-up times and sustain power outputs during brief cloudy/stormy periods
  - Heat-generating capacity no more than 5% of the heat supplied by the heliostats
  - Operation no more than 4 h/day
  - Average boiler usage of less than 1 h/day

- Water
  - Source: on-site well
  - Consumption (mirror washing, miscellaneous industrial processes, potable use): <100 ac-ft/yr (123,350 m^3/yr) total for all three plants

- Construction period: 48 months (all phases with some overlap)

- Employment
  - Construction: 959 total jobs (averaging 474 over entire construction period)
  - Operation: 90 full-time employees

F.2.4 Common Systems and Hybrid Systems for Parabolic Trough and Power Tower Facilities

F.2.4.1 Power Plant Systems

Although the mechanisms for producing steam are different for parabolic trough and power tower facilities, the downstream power-generating activities of both technologies are essentially identical. The power plant system, sometimes referred to as the power block, is defined as that portion of the facility at which electrical power is generated. In typical parabolic trough and power tower facilities that generate electricity from only solar energy, the power block includes the (1) steam heat exchanger at which steam is produced, (2) STG that produces electricity, and (3) electrical equipment contained in a substation where the electrical power is converted to AC, transformed to the appropriate voltage, conditioned, and otherwise synchronized for delivery to the bulk electrical grid to which the solar facility is connected. All components of the power block from the steam condenser downstream are virtually identical in form and function to the components composing the power blocks of a conventional fossil fuel thermal power plant.

Superheated steam from the heat exchanger drives a Rankine cycle STG. Leaving the STG, the spent steam is condensed in a standard condenser, and condensate is returned to the heat exchanger via condensate and feedwater pumps after appropriate chemical treatment. Heat absorbed by the steam condenser can be rejected by a variety of cooling systems (see Section F.2.4.2).

The balance of plant for the power block typically includes a SCADA system to monitor and control plant operations, the various pumps and piping systems by which HTF and steam water are circulated, air compressors, the steam condenser, the chemical treatment equipment used to condition the steam condensate before recycling, and the cooling system used to reject heat from the steam condenser (including chemical treatment equipment when cooling water is recirculated). Much of this equipment is likely to be housed in a central operations building. Warehouse and shop buildings are also likely to be present. Also typically present are diesel-fueled emergency generators and/or storage batteries to provide power during power failures for safe shutdown of AC and DC internal plant loads. Raw water for steam cycle and cooling-water makeup and for firefighting can also be expected to be stored on-site. Tanks for steam condensate, deionized water, steam cycle treatment chemicals, and process wastewater, and an HTF reservoir are also likely to be present.

F.2.4.2 Cooling Systems

All CSP systems that produce steam must also be able to condense and recycle that steam. Information provided in this section is therefore applicable to both parabolic trough and power tower facilities. Because the efficiency of a Rankine cycle STG is governed in large part by the pressure and temperature of the steam both entering and leaving the turbine, the steam condensing/cooling system directly affects overall facility performance.[37] Steam condensation is the single greatest water demand associated with electrical power generation utilizing a steam cycle. A 100-MW parabolic trough facility using a Rankine cycle STG with recirculating wet cooling is estimated to require about 750 ac-ft/yr (925,110 m^3/yr) of water (Dahle et al. 2008). Such cooling systems (see Section F.2.4.2.1) can be expected to account for approximately 90% of that water volume (through evaporation and drift), with another 8% consumed in maintenance of the chemical quality of both the steam water and the cooling water before recycling (e.g., through replacement of blowdown water),[38] and 2% consumed in plant maintenance (e.g., for parabolic trough plants, primarily associated with regular washing of the mirrors).

Rejecting heat through condensation of steam from the steam cycle by means of a recirculating wet-cooling system is technically feasible for CSP facilities. However, the principal mechanism for heat rejection in a recirculating wet-cooling system is evaporation of some portion of the cooling water; approximately 1 pound (0.12 gal at 70°F) of water is lost to evaporation for each pound of steam condensed (Kelly 2006b). In a power plant with a nominal rating of 80 MWe operating at a capacity factor of 27%, this rate of evaporative loss can amount to approximately 5.33 ac-ft/yr (6,575 m^3/yr) (Kelly 2006b). Because the ideal location for a solar facility is often in arid or semiarid desert environments where water availability is limited, controlling consumptive uses of water is critical not only to the performance but also to the very viability of the facility.

Because steam condensation represents the greatest consumptive use of water in parabolic trough and power tower plants, the cooling system becomes a critical design element, especially for facilities sited in water-deprived areas. Four basic cooling system options exist for

[37] It has been estimated that for parabolic trough facilities, for every 1ºF rise in temperature of steam condensate leaving the condenser, power production is decreased by approximately 1% (Kutscher et al. 2006).

[38] To remove suspended solids and to control scale, bacterial growth, corrosion, and a variety of other problems in systems that recirculate water, a certain amount of the water is periodically removed and replaced. When the quality of the replacement water source is high, blowdown can account for as little as 1% of the total volume of water in the system. However, poor-quality replacement water can require blowdowns of as much as 20% of the system volume. In most cases, the makeup water is treated to meet prescribed quality and performance factors before being introduced into the system.

thermoelectric power plants: (1) once-through (or open-loop) wet cooling, (2) recirculating (also known as closed-loop) wet cooling, (3) dry cooling, and (4) hybrid wet/dry cooling. The use of once-through wet-cooling systems for thermoelectric power plants can reasonably be expected to be confined to locations with plentiful surface water supplies (e.g., coastal areas and locations adjacent to rivers, lakes, or reservoirs). On average, once-through cooling systems can be expected to withdraw between 400 and 600 gpm (1.5 and 2.3 m^3/min) for every megawatt of power produced in a conventional steam cycle power plant (EPRI 2004a). Because once-through cooling systems are obviously not compatible with arid environments and are not likely to be selected as the cooling system for either parabolic trough or power tower facilities being developed in the six-state study area of this PEIS, they are not discussed further.[39]

The following sections discuss the cooling systems that would be used by either parabolic trough or power tower facilities in the PEIS study area and the water requirements for each.[40]

F.2.4.2.1 Wet-Cooling Systems. The most common cooling system employed in thermoelectric power plants is known as the wet recirculating system, or the wet closed-loop system. Although the wet closed-loop cooling system is not entirely closed, the majority of the water in the system is retained and recirculated, allowing the system to withdraw substantially less water than a once-through system. Spent steam leaving the STG is directed to a water-cooled condenser where it is cooled before being recycled in the steam cycle. Heated cooling water rejects the heat it absorbed from the condenser at a cooling tower where it is allowed to interact with a counterflow or crossflow of ambient air. Two variants of the closed-loop cooling tower are in use: the mechanical draft tower, where fans direct a flow of ambient air against cooling water cascading over a series of plates, and the natural draft cooling tower, where the flow of ambient air is produced not by fans but by simple convection that causes the air to rise up a tower counter to cascading cooling water. Some portion of the water evaporates into the atmosphere, taking heat energy away from, and thus cooling, the remaining water in the cooling loop. Some smaller fraction of water is also lost through drift, where droplets of water are actually entrained in the counterflow of air and exhausted to the atmosphere. Both cooling tower designs have essentially the same water demands. Although specific cooling system designs, operating conditions, and circumstantial factors (including climatic conditions) all can affect the overall efficiency of a wet-cooling system, it can be reliably anticipated that between 10 and 15 gal (0.038 and 0.057 m^3) of water will be lost per minute to evaporation and drift for every

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[39] Recent amendments to Sections 316(a) and (b) of the federal Clean Water Act and National Pollutant Discharge Elimination System (NPDES) regulations make it highly unlikely that once-through cooling systems will be used in any new utility-scale power-generating facility.

[40] While the steam cycles and cooling system options are the same for parabolic trough and power tower facilities, power tower facilities can operate at substantially higher temperatures than parabolic trough facilities. Substantially more heat can be recovered than would be necessary to produce saturated steam. This excess heat can be used to support the TES system, or it can be used to produce supercritical or even ultra supercritical steam. At this time, no power tower facilities have been built or proposed that would use supercritical or ultra supercritical steam, so the impacts of these technologies on cooling system design and operation are not discussed further.

megawatt of electrical power produced using conventional STGs (CEC 2002).[41] This typically equates to a loss of 1% to 2% of the total volume of water present in the cooling loop to evaporation and would translate to an ongoing water replacement need (i.e., water consumption rate) of 10 to 15 gpm (0.038 to 0.057 m^3/min)/MWe (600 to 900 gal [2.27 to 3.41 m^3]/MWh) being produced.

Evaporation and drift represent water consumption mechanisms associated with wet closed-loop cooling, the volumes of which must be replaced. Over time, as water evaporates at the cooling tower, the dissolved solids content of the remaining water increases, as does the potential for scale and for the growth of biological organisms. Consequently, recirculating cooling water is treated to reduce the potential for scale formation (i.e., the precipitation of dissolved solids, which will reduce cooling tower efficiency), and biocides and/or chlorine are added to control the growth of biological organisms, especially algae.[42] To further control the chemical quality of the water, a small portion typically is removed as "blowdown" in each recirculation cycle. The amount of water removed through blowdown depends on many factors, including the initial quality of the water introduced into the cooling cycle. A reliable estimate is that for a wet closed-loop cooling system recirculating water at 500 gpm (1.89 m^3)/MWe, approximately 2 gpm (0.008 m^3/min)/MWe of cooling water will be removed through blowdown (CEC 2002).

DOE (2009) reports that parabolic trough plants using wet closed-loop cooling can be expected to withdraw about 800 gal (3.03 m^3)/MWh (780 gal [2.95 m^3] of which is consumed by evaporation at the cooling tower and the amount required to replace blowdown, and 20 gal [0.076 m^3] of which is used for noncooling-related activities such as mirror washing). In comparison, with the use of similar closed-loop cooling systems, a solar power tower facility would use 600 gal (2.27 m^3)/MWh; conventional coal-fired or nuclear power plants can be expected to withdraw as much as 500 gal (1.89 m^3)/MWh of electricity; and a combined-cycle natural gas plant[43] would use 200 gal (0.76 m^3)/MWh. Solar dish engine facilities that require water only for mirror washing and other maintenance functions consume 20 gal (0.076 m^3)/MWh. A detailed analysis of the performance metrics of wet closed-loop cooling systems for CLFR facilities has not been completed. However, it is expected that cooling water demands will be slightly higher than for similarly sized parabolic trough plants because of the

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41 Of this amount, most is lost to evaporation. Cooling towers equipped with modern drift eliminators can substantially reduce the amount of water lost to drift and are typically designed to reduce drift losses to 0.002% of the circulating water flow or less.

42 The use of chlorine in treating recirculating cooling water has been investigated for its potential to cause the formation of trihalomethanes by interactions with organic matter in the water, especially in open-loop wet-cooling systems where organic matter in the form of airborne insects is introduced. Trihalomethanes are generated, however, because power plants typically chlorinate their cooling water only a few times a day to maintain adequate biological control. The rate at which trihalomethane generation occurs in freshwater cooling systems is slight and thought to represent only negligible health impacts on exposed workforce personnel (EPRI 2004b).

43 A combined-cycle natural gas plant would be expected to consist of a combustion turbine generator operating in conjunction with heat recovery steam generators (HRSGs). See Section F.2.4.5 for additional details.

CLFR's expected lower operating temperatures and lower thermal efficiencies (i.e., greater amounts of heat rejected per MWe produced).[44]

F.2.4.2.2 Dry-Cooling Systems. Dry-cooling (or air cooling) systems can be either direct or indirect in their design. Direct dry-cooling systems function by directing a flow of ambient air across condenser tubes through which the spent steam from the STG is circulated. Indirect dry-cooling systems introduce a closed cooling-water loop that accepts heat from the spent steam in a closed condenser and then ultimately rejects that heat to the atmosphere in an air-cooled condenser (i.e., radiator). With dry-cooling systems, overall water consumption is reduced by as much as 90% over conventional wet-cooling systems because both evaporation and drift at the wet closed-loop cooling tower are eliminated. However, plant-wide consumptive uses of water are not completely eliminated with conversion to dry cooling of steam. Other ongoing uses include replacing steam cycle blowdown, general plant maintenance activities (including regular washing of solar collectors), and potable consumption. Collectively, however, these other consumptive uses would be equal to no more than 10% to 15% of the consumptive uses in wet-cooling systems and can be expected to average 80 gal (0.30 m^3)/MWh of electricity produced (depending on local conditions and cooling system design). EPRI (2004a) estimates that a 350-MW coal-fired plant would realize a water savings of approximately 6,400 ac-ft/yr (~2 billion gal/yr) (7.9 million m^3/yr) in switching from wet closed-loop cooling to dry cooling. Likewise, a 500-MW natural gas combined-cycle plant would realize savings of 2,800 ac-ft/yr (~ 900 million gal/yr) (3.5 million m^3/yr).

Although dry-cooling systems require considerably less water than do wet-cooling systems, they have shortcomings. For example, capital costs are higher, as are auxiliary power loads (parasitic power losses). Because dry-cooling system efficiencies increase with increasing temperature differentials between the materials being cooled and the cooling agent, dry-cooling systems operating in desert environments where the ambient air temperature is generally high can be expected to have lower cooling efficiencies than wet-cooling systems operating at the same locations.[45] Such lower system efficiencies are expected to be most apparent on the hottest days when electrical demand is highest and the plant can be expected to be operating at capacity (DOE 2009). Such lower cooling system efficiencies ultimately translate to a net power loss.[46] (See Section F.2.4.2.4 for additional discussion on performance penalties from dry-cooling systems.)

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[44] Although all the water consumption values cited in this paragraph are believed to be generally representative, it is important to note that water consumption from wet open-loop cooling systems is location dependent, with the overall performance of the cooling system influenced by many factors, especially including, climatic conditions of average ambient air temperatures and relative humidities.

[45] Wet-cooling system efficiencies are also dependent on the temperature differentials (between incoming cooling water and counterflowing ambient air), albeit to a much lesser degree.

[46] This power reduction reflects not only the lower thermal efficiencies of the cooling system, but also the higher parasitic load of fans used in dry, air-cooled systems compared to fan loads of wet recirculating systems of equivalent capacity.

F.2.4.2.3 Combined Wet/Dry Cooling Systems. Combined wet/dry cooling systems may provide an acceptable alternative in desert environments where water is scarce. Such systems contain both the conventional wet-cooling tower and a dry-cooling surface condenser that can be placed either in parallel or series arrangements. In series, spent steam is first sent to the dry-cooling system and then further cooled in the wet system. In the parallel arrangement, distribution of spent steam from the STG to either cooling system is at the discretion of the plant operator. In either configuration, hybrid wet/dry cooling systems would represent somewhat higher internal loads than a simple wet recirculating system, and this higher load would translate into a loss in net power production. DOE estimates that over a range of possible wet/dry cooling configurations, water savings can range from 80% to 90% (over conventional wet recirculating cooling) with net power losses from 2% to 10% (DOE 2009).[47] Ostensibly, dry cooling would be used most of the time; however, during very hot periods when dry cooling efficiency is at its lowest and parasitic load is highest, more spent steam would be sent to the wet-cooling system. Although the initial capital costs of such a dual system are obviously higher, as are the maintenance and operating costs, the flexibility that such a system offers may prevent significant decreases in overall power-generating efficiency and output during high-demand periods while still staying within the constraints of limited water availability.

A unique family of variants to combination wet/dry cooling is known as enhanced air cooling or "evaporative enhancement." In such a system, a fine mist of water is sprayed into the airstream that is directed toward a dry-cooling surface condenser. Alternatively, cooling air is passed through a wet media filter placed ahead of the condenser, or water is "deluged" onto the surface of the condenser as ambient air is directed over it. In desert environments where the relative humidity of the ambient air is low and the temperature is well above the dew point, the water quickly evaporates, effectively cooling the air in the airstream to an extent proportional to the amount of water introduced. Drawbacks for such water-enhanced dry systems include the following:

- Increased capital investments;

- Higher parasitic loads for fans (especially for wet media filters that introduce significant pressure drops, which fans must overcome);

- Scaling (especially for condenser deluge systems that use water with high concentrations of dissolved solids); and

- Increased maintenance costs.

Furthermore, an increase in internal loads also represents a loss in net power output. Nevertheless, water savings can be dramatic. Figures F.2.4-1, F.2.4-2, and F.2.4-3 depict enhanced spray, enhanced wet media, and enhanced deluge wet/dry cooling systems.

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47 The range of net power loss expected reflects primarily variations in cooling system efficiencies as a result of ambient conditions of temperature and humidity. In the desert Southwest, efficiencies of wet-cooling systems are high due to relatively high ambient temperatures and low relative humidity. However, the high ambient temperatures tend to decrease the efficiencies of air-cooled condensers.

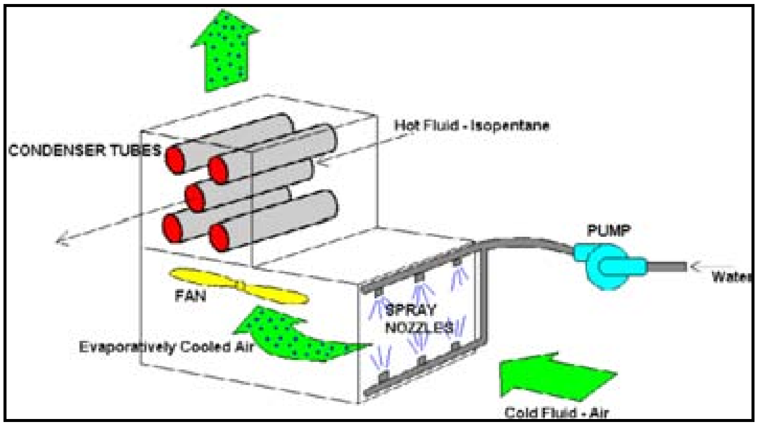

FIGURE F.2.4-1 Enhanced Spray Wet/Dry Cooling (Source: Kutscher et al. 2006)

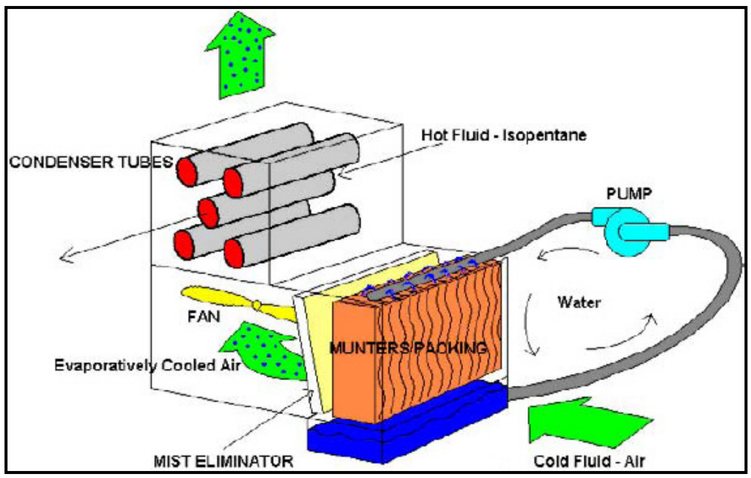

FIGURE F.2.4-2 Enhanced Wet Media Wet/Dry Cooling (Source: Kutscher et al. 2006)

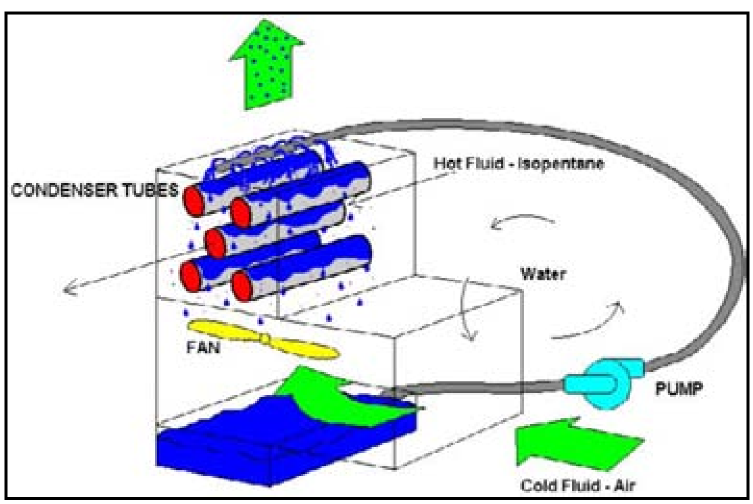

FIGURE F.2.4-3 Enhanced Deluge Wet/Dry Cooling (Source: Kutscher et al. 2006)

F.2.4.2.4 Performance Penalties Resulting from Alternative Cooling Systems. The various alternatives to conventional wet closed-loop cooling discussed above all result in reductions in the amount of water needed for cooling to support a thermoelectric facility. In that regard, they all deserve consideration as substitutes to wet closed-loop cooling in a solar thermoelectric facility located in arid, water-deprived areas. Further, because the performance of these systems is maximized in the ambient conditions typical in arid environments (ambient air with low relative humidity), they offer ideal alternatives to conventional wet closed-loop cooling. However, all such alternative cooling systems come with a performance penalty in the form of a net loss of power production capability. In general, alternative cooling systems have lower thermal efficiencies than wet closed-loop systems, even in climatic conditions where their performance is optimal. Such lower efficiencies result in higher steam condensate temperatures, higher back pressures at the steam turbine, and lower steam turbine efficiencies. Additionally, higher parasitic loads for some alternative cooling systems further contribute to net power losses.

DOE (2009) reports that the net electric power output of a trough plant using air cooling would drop by 4.5% to 5% and that of a solar power tower facility would drop by 1.3% over equivalent plants using wet closed-loop cooling. Performance penalties actually increase during the hottest periods of the day, periods that are likely to coincide with highest electricity demand (primarily for air conditioning). During the hottest 1% of the day, the performance penalties for parabolic trough and power tower facilities using dry cooling would increase to 17.6% and 6.3%, respectively.[48] However, increasing the size of the solar field and the resulting increase in steam production could offset any net power loss associated with a switch to dry cooling.

Performance penalties for wet/dry cooling systems are somewhat less dramatic. A facility using a typical wet/dry system can realize a 50% reduction in water consumption (compared to a wet closed-loop cooling system) while suffering only a 1% drop in net power production. That same facility can be designed to save as much as 85% of water consumption with only a 3% drop in net power production (DOE 2009). Kutscher et al. (2006) estimate net power losses from misting or wet media cooling systems and from deluge systems at 40 kWh/1,000 gal (3.79 m^3) of water used and 60 kWh/1,000 gal (3.79 m^3) of water used, respectively. Further, the savings in water consumption as well as the net power loss suffered can both be influenced by the manner in which wet/dry cooling systems are operated. For example, diverting more of the steam cooling responsibilities to the wet-cooling system during the hottest hours of the day could significantly reduce the net power loss that would be experienced if all the cooling demands were met by the dry-cooling mode during those periods. Pursuing such operating flexibilities, facility operators could expect to reduce total water usage by 80% to 90% while suffering net power losses in the range of 2% to 10%, depending on local conditions and cooling system designs and operating flexibilities.

[48] The performance penalty for compact linear Fresnel reflector facilities has not yet been established, but is estimated to be somewhat higher than that for parabolic trough facilities because of their somewhat lower operating temperatures (DOE 2009).

F.2.4.3 Thermal Energy Storage Options

A “solar-only” facility using either parabolic trough or power tower technology would be simple to construct and operate and would offer numerous environmental advantages, including few to no emissions of air pollutants during operation.[49] However, it would be capable of producing power at its nameplate rating only when the DNI matches its design basis. During periods of reduced DNI or at night, power production would be greatly reduced or stopped entirely. Nevertheless, utility-scale facilities of such a design are feasible and have recently been proposed (see Section F.2.2.2.1). For grid-connected facilities, this lack of dispatchability greatly reduces the value of power from such solar-only facilities.

Adding TES capabilities to a parabolic trough or power tower facility[50] greatly increases the dispatchability and reliability of the plant as a source of grid-connected power and can also improve the facility’s overall power-generating capacity. TES can increase the capacity factors of parabolic trough or power tower facilities from 25% to more than 70% (NREL 2008a). (The capacity factor is the percentage of time over which useful amounts of power are produced.) The decision to construct a facility with TES requires a fundamental change to the design basis.

Although many materials could serve as heat storage media, a eutectic mixture of molten salt, typically a binary mixture of 60% sodium nitrate [$Na(NO_3)$] and 40% potassium nitrate [$K(NO_3)$], has been the subject of the majority of investigations and feasibility studies. A mixture of 48% calcium nitrate [$Ca(NO_3)_2$], 7% sodium nitrate, and 45% potassium nitrate, available commercially as Hitex XL®, has also been investigated.[51]

Both direct and indirect TES designs involving molten salt have been conceptualized. In the direct design, the conventional synthetic oil HTF is replaced with molten salt, circulated between the solar field and a storage facility consisting of one or two tanks, and subsequently circulated between its storage location and a conventional steam heat exchanger. In the indirect design, the solar field continues to use a conventional synthetic oil HTF to transfer heat from the

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49 Depending on anticipated weather conditions at the selected location, a “solar-only” plant may also use a natural gas- or propane-fired heater to heat the HTF when ambient temperatures are expected to fall below its eutectic point. Such a heater may also be used to preheat the HTF to aid in rapid plant start-up. Also, chemicals used in the treatment of recirculated cooling water may be emitted from the cooling tower in minor amounts as drift (see Section F.2.4.2).

50 Although most RD&D on TES has been directed toward its application for parabolic trough facilities, research indicates that analogous TES applications to power tower facilities would, in many cases, be equally feasible.

51 Many other technological approaches to TES have been identified, including storing heat in a concrete block buried beneath the solar field (through which hot HTF would circulate), and storing heat in the form of pressurized hot water in underground formations below the solar energy facility (where it would “flash” into steam as its pressure is relieved, bringing it to the surface through a recovery well). For details, see http://www.nrel.gov/csp/troughnet/pdfs/tamme_concrete_storage.pdf and http://www.sciam.com/article.cfm?id=sunny-outlook-sunshine-provide-electricity&page=1; accessed Jan. 5, 2009. Both technologies are currently undergoing development, but neither has been proposed for commercial application and, consequently, neither is discussed further here. The DOE is also funding various RD&D projects for CSP, including many involving development of low-cost TES technologies. For details, see http://www.energy.gov/news/6562.htm; accessed Jan. 5, 2009.

solar field to molten salt in storage.[52] During those periods when DNI is reduced or has stopped entirely, the molten salt is used to produce steam that is directed to the STG for uninterrupted power production.

The primary advantage provided by TES is the ability to produce power (in many cases, at or near the facility's nameplate rating) during periods of less-than-ideal insolation, including during nighttime hours. Since many electricity load peaks occur in early morning or early evening hours, adding this ability to a facility greatly enhances its value as a source of utility-scale power. A second equally important advantage can also be realized when molten salt replaces conventional HTF: the facility can operate at a higher temperature range (842°–932°F [450°–500°C]) than the typical operating temperature of a plant using synthetic oil HTF (740°F [393°C]). This, in turn, allows the Rankine cycle STG to improve in efficiency from 37.6 to 40%, thus increasing the overall power-generating capacity of the facility with virtually no change to the footprint of the solar field and minimal changes to the overall facility footprint.

Adding TES capability greatly affects the configuration and size of the solar field. Without a TES element, a facility would be expected to have a solar field only large enough to supply the amount of heat needed to produce steam and generate power (under anticipated peak insolation and meteorological conditions) at the facility's peak power rating.[53] Such a facility is said to have a solar multiple of 1.0 (see also Section F.2.2.3). Facilities with TES capability must be able to generate more heat than would be required to meet nameplate ratings, with the extra heat being that which is stored in the TES. Such facilities will invariably have larger solar fields with solar multiples proportional to the amount of heat expected to be delivered to the TES, generally a factor of how many hours the facility would be capable of delivering power at nameplate rating without concurrent insolation.

Practical limitations exist as to the length of time heat can be stored in molten salt systems. At the current stage of technology development, most feasibility studies identify 6-hour storage (i.e., sufficient to provide full-load power for as long as 6 hours) as the practical upper limit. The molten salt can be stored in one tank (also known as a thermocline) or in two tanks (a hot tank and a cold tank). Each storage configuration is supported by its own unique configuration for circulating the molten salt between its storage location and the STG and for replacing the heat lost in steam generation with heat recovered from the solar field.

Figure F.2.4-5 (below, in Section F.2.4.4) provides an example schematic of a parabolic trough–TES system. It has been estimated that a parabolic trough facility with 6 hours of molten salt storage, operating at a nominal salt temperature of 842°F (450°C) and using a two-tank storage configuration, can reduce the LCOE as much as 14.2% (and more than 20% when using a thermocline storage configuration) compared to a state-of-the-art conventional parabolic trough

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[52] Although replacing the synthetic oil HTF with molten salt without also adding storage capacity for molten salt is technically feasible, early studies concluded that using molten salt as an HTF without also including the ability for its use as a long-term TES medium was not economical (Kearney et al. 2004).

[53] As a practical matter, solar fields in commercial utility-scale solar-only facilities can be expected to be somewhat larger than what would be required to meet nameplate power expectations, allowing some of the field to be isolated and shut down for maintenance and repair without compromising the facility's power capacity.

facility without TES (see Section F.2.2.3). Even greater improvements to overall facility efficiencies and even greater reductions in LCOE could be realized if the engineering challenges of operating the molten salt system at even higher temperatures could be overcome.

The most salient engineering and O&M issues associated with the use of molten salt TES include the following:

- The higher freezing points of molten salt eutectic mixtures over conventional HTFs (248°F to 428°F [120°C to 220°C] for binary and ternary salt formulations, respectively, versus 60°F [15°C] for conventional synthetic oil HTF) require additional design considerations to prevent salt freezing in transfer piping.

- There is greater potential heat loss in receivers and transfer piping due to higher operating temperatures.

- The corrosive action of molten salts on their containment and circulation systems and components requires modifications involving more resistant materials, which are more expensive.[54]

- The overall higher operating temperatures may require alternative components in the salt transfer and storage systems (e.g., flexible connections between individual receivers and transfer pumps may need to be built to closer tolerances and with alternative materials to operate at higher temperatures for extended periods).

- To improve cold start-up times and avoid potentially damaging temperature gradients throughout the system (thermal stresses), some mechanism for preheating the HTF in the solar field may be necessary.

- Heating of transfer piping and storage containers may be necessary in the event of the failure and long-term inoperability of the salt circulation system, resulting in higher parasitic loads and possibly air pollutant emissions if the heat source involves combustion of fossil fuels.

- There are higher parasitic loads related to transfer pumping of molten salt versus less viscous synthetic oil HTF.

- There is a 50% increase in O&M costs and O&M manpower requirements (NREL 2004).

[54] Although the pure nitrate salts are expected to be only minimally corrosive, the presence of contaminants, such as chloride and perchlorates, and water, can greatly enhance the salt's corrosive properties.

Various options have been identified to successfully address these and other engineering issues.[55] However, all such solutions increase the complexity of the facility. This is reflected in increased capital costs and O&M costs, and a reduction in overall plant capacity due to an increase in parasitic load. Nevertheless, feasibility studies have shown that these extra costs and considerations do not devalue the option more than the value added from TES incorporation (Kearney et al. 2004).

Although the initial focus of TES technology development has been limited to investigating its applicability to parabolic trough and power tower facilities, the Solar Energy Technologies Program (SETP) of the DOE's Office of Energy Efficiency and Renewable Energy (EERE) is working to expand TES options for solar energy facilities. In addition to supporting a variety of initiatives aimed at reducing the overall costs and improving the overall thermal efficiencies of traditional TES systems and applications, thereby lowering the cost of energy TES-equipped facilities can produce, the SETP is directing research into development of advanced HTFs. Such advanced systems include, for example, the use of phase change materials (PCMs) (i.e., materials whose physical state changes as they absorb heat) and nanofluids as a thermal storage media. Novel applications of TES, for example, use of TES at solar dish engine facilities, are also being investigated. [56]

F.2.4.4 Solar/Fossil Fuel and Solar/Renewable Fuel Hybrid Systems

Hybrid facilities combining solar energy technologies with conventional fossil fuel technologies or other renewable energy technologies can greatly improve the dispatchability and reliability of the power being produced. Many combinations coupling CSP technologies with power-producing technologies that use other forms of energy are technically feasible. These hybrid systems could include integration with new or existing coal-fired power plants or with other renewable technologies that involve thermoelectric generation (e.g., geothermal and biomass combustion).[57] The most likely hybridizations, however, would couple parabolic trough or power tower[58] CSP with either a natural gas–fired combustion turbine generator (CTG) working in combination with heat recovery steam generators (HRSGs), and/or a natural gas–fired boiler that can augment steam produced by the solar field.

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[55] For example, continuous circulation of the salt HTF throughout the night, or use of an auxiliary natural gas-fired heater or electric heat tracing tape on the transfer piping, can prevent salt freezing.

[56] For additional details on this as well as other ongoing TES R&D projects, see the DOE Solar Energy Technologies Program Web site at http://www1.eere.energy.gov/solar/pdfs/csp_funding_prospectus_2008.pdf.

[57] Nuclear power is also classified as thermoelectric. However, hybrids between solar CSP and nuclear power plants, while technically feasible, are impractical and not likely to materialize. Although excellent geothermal resources exist within the six-state study area near high-value solar resources, no such combination of technologies has yet been proposed. Although arid desert areas that are most likely to have the best solar resources would not be expected to be near significant biomass resources, one facility combining solar thermal and biomass thermoelectric technologies has been proposed for a desert region of California.

[58] Although both parabolic trough and power tower CSP plants lend themselves equally well to hybridization with other thermoelectric generating technologies, only hybrids involving parabolic troughs have been proposed or built to date.

Combustion turbines do not produce steam but instead drive a turbine with high-temperature, high-pressure gases generated through the combustion of fossil fuels, typically natural gas. Consequently, their use does not increase steam condensate cooling water demand. However, CTGs do use water to cool the inlet combustion air that has been compressed to high pressure before being introduced into the combustion zone of the turbine.[59] When the exhaust gas leaving the turbine is exhausted directly to the atmosphere, the CTG, known as a simple- or single-cycle CTG, operates at an efficiency of about 35% to 38%. Because the gases exhausted from a CTG still possess a considerable amount of heat energy, CTGs are often used in conjunction with HRSGs that can use latent heat in the exhausted gases to produce additional steam. By comparison, Rankine cycle turbines can operate at overall efficiencies as high as 40%. Brayton cycle turbines equipped with HRSGs can reach efficiencies as high as 80%.[60] Combined-cycle power plants involve the simultaneous but independent operation of both Rankine cycle and Brayton cycle turbines (coupled, in most instances, with HRSGs).[61]

Conceptually, many combinations of steam-generating technologies can be combined with parabolic trough or power tower technologies and CTGs to result in ISCC facilities.[62] In such configurations, the solar field would be capable of producing steam and/or providing some heat energy to the bottoming cycle of the fossil fuel combined-cycle plant STGs. Figures F.2.4-4 and F.2.4-5 demonstrate two of the most likely hybridizations: a parabolic trough plant combined with a natural gas-fired boiler, both feeding an STG, and an ISCC facility hybridizing a parabolic trough solar plant with a natural gas-fired CTG and HRSG, respectively.

While solar dish engines can be operated in parallel with any thermoelectric generating technology, the advantages of such combinations are minimal since very little of each technology can utilize shared equipment. Such hybrids, therefore, would represent nothing more than collocation of two fundamentally different technologies that actually create a complex facility with respect to O&M because of their disparate natures. The dish engine itself does have a hybridization option, however, in that it can be modified to run on conventional fuels, essentially

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59 A CTG's performance relies on mass flow of inlet air. High ambient temperatures, combined with additional heating of inlet air due to compression, reduce the density (and thus mass flow) of turbine inlet air. Spraying water into the inlet air stream, which allows evaporative cooling to take place, restores the mass air flow and avoids loss of turbine performance. Cooling inlet air by introducing a fine spray of water is known as "fogging" and can represent the third-largest consumptive use of water in a combined-cycle power plant. Typically, as much as 125 to 160 gal (0.47 to 0.61 m^3) of water is used for every megawatt-hour of power produced by the CTG, operating at design conditions (Maulbetsch and DiFilippo 2006).

60 The efficiencies being measured here are the conversion of heat energy to electricity.

61 Brayton cycle turbines working in conjunction with HRSGs are also combined-cycle plants. Combined-cycle plants can also function as cogeneration (Co-Gen) plants in which a fraction of the steam produced is used for industrial processes rather than power generation. Co-Gen plants are considered outside the scope of this PEIS.

62 A combined-cycle power plant is one that uses two or more different thermodynamic cycles to produce power. Most commonly, a conventional STG operating on the principles of a Rankine thermodynamic cycle is operated simultaneously with a CTG that operates in accordance with a Brayton thermodynamic cycle. Also, CTGs operating alone are sometimes referred to as simple cycle, but when working in conjunction with HRSGs that use the heat contained in the CTG's exhaust to produce steam, the system is also sometimes referred to as a combined cycle.

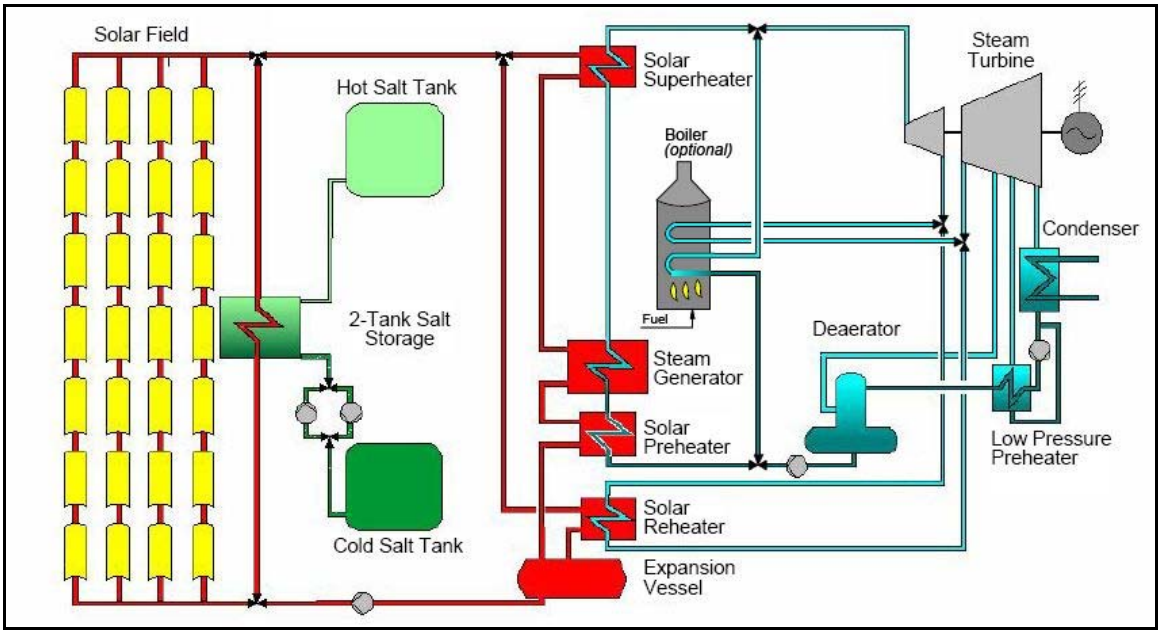

FIGURE F.2.4-4 Process Flows for a Typical Parabolic Trough Power Plant with Two-Tank TES Operating in Conjunction with a Natural Gas-Fired Boiler (Source: NREL, as presented in SDRREG 2005)

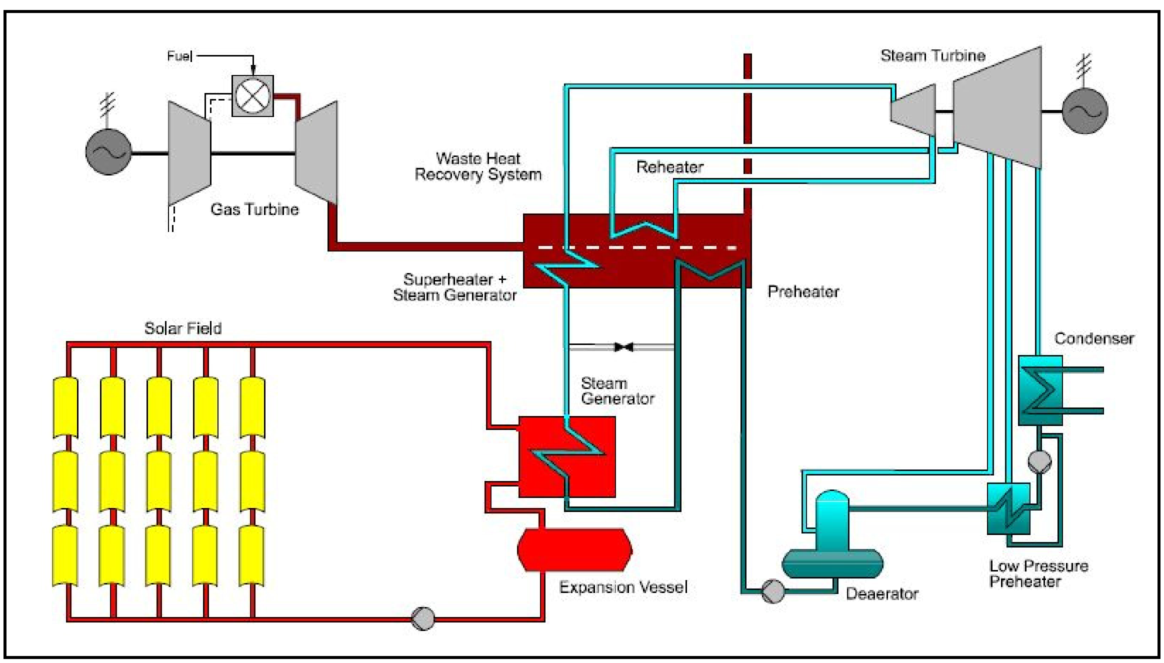

FIGURE F.2.4-5 Process Flows for an Integrated Solar Combined Cycle (ISCC) Facility Combining a Parabolic Trough Plant with a CTG and HRSG (Source: NREL, as presented in SDRREG 2005)

converting a Stirling-type heat engine into a conventional internal combustion engine (ICE) similar to the type used in today's vehicles. Any of these dual-fuel systems would allow undiminished power production during short periods of less than ideal solar intensity or power production after sunset (albeit, perhaps at a somewhat diminished rate). However, although technically feasible, no such utility-scale hybrids have been built or proposed.

Most hybridizations are designed to enhance both the power-generating capacity and the dispatchability of the solar facility. One hybrid, however, addresses only the facility's dispatchability. That hybrid configuration involves adding a natural gas- or propane-fired heater not to produce additional steam but to maintain a minimum temperature for the HTF during periods of low DNI and at night. Such a feature would shorten the amount of time after sunrise or stormy/cloudy periods before the solar facility was again capable of producing sufficient steam to generate utility-scale amounts of electricity.[63] Because most regions experience high load demands in the early morning hours, features that can shorten the effective start-up time of the solar facility increase its value as a reliable and more dispatchable power source. In comparison to configurations in which a natural gas boiler is used to produce additional steam, fuel consumption by such HTF heaters is substantially less.

The rate of water consumption for hybrid parabolic trough facilities can be greatly affected by the operation of the non-solar power-producing equipment. Boilers that provide supplemental steam have steam-cooling demands commensurate with the character and amount of steam they produce and other factors relating to the designs and efficiencies of their steam cycles. CTGs do not require steam condensate cooling since they do not produce steam, but they do require water to cool the compressed air introduced at the inlet to function at their highest performance levels. For example, in a hybrid plant where equal amounts of power are produced by the solar field and the CTG, water consumption per megawatt is reduced by something less than half. Hybridizing solar with a natural gas-fired boiler producing steam with the same characteristics as the steam produced by the solar field, however, is likely to have little to no effect on the overall water-per-megawatt consumption rate.

As discussed in Section F.1.1, the environmental impacts of the fossil fuel-driven portions of such hybrid facilities are not evaluated in this PEIS. However, additional background information on the numbers and types of such existing and proposed facilities is given here to provide a broad understanding on the status of hybrid solar development.

A hybrid facility combining parabolic trough technology with two natural-gas-fired CTGs, two HRSGs, and one STG, the Victorville 2 Hybrid Power Project, has been proposed for the vicinity of Victorville, in San Bernardino County, California (Inland Energy, Inc. 2007). An AFC was submitted to the CEC on February 28, 2007. The project was approved on July 16, 2008.[64] Although many combinations of CSP technology with fossil fuel power-generating

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63 An HTF heater would not increase water demand but would result in emissions of criteria pollutants. However, to the extent that a solar facility so equipped could come on line sooner in the day, possibly replacing a fossil fuel- generating facility, the net result could be a reduction in criteria pollutants.

64 The complete AFC and other related documents are available at http://www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/. Accessed Jan. 5, 2009.

technology are possible, the Victorville 2 Hybrid Power Project is considered to be representative of most future ISCC-type facilities.

The Victorville 2 Hybrid has a nameplate rating of 570 MW, 520 MW of which originates from the heat generated by combustion of natural gas and only 50 MW of which originates from heat captured in a collocated parabolic trough facility. The engineering parameters and environmental resource requirements for this facility, therefore, reflect profiles more closely associated with fossil fuel–fired power plants than with parabolic trough plants, even though some of the major components associated with the steam cycle (including steam condensation and cooling systems) serve both the solar and nonsolar portions of the plant.

F.2.5 Solar Dish Engine CSP[65]

The solar dish engine is unique among CSP technologies; it relies on DNI but generates electricity through the action of an external heat engine rather than steam production. The system consists of a parabolically shaped reflector/concentrator, a receiver located at the mirror's point focus, an external heat engine, and an induction generator or alternator. The reflector concentrates incident solar energy onto a receiver, which, in turn, transfers heat to a "working gas" (most typically hydrogen or helium) contained in a sealed system known as an external heat engine.[66] As this working gas is superheated,[67] its increasing pressure drives a piston, producing mechanical power that drives an induction generator in each dish's power conversion unit to produce electricity. Individual dish engines have been designed with power-generating capacities of 0.025 to 0.050 MW.

The heat engine most typically used in solar dish engines is called a Stirling-type engine, named after the 19th-century minister who first applied the thermodynamic principles of the Carnot cycle to his patented design for an engine that produced mechanical work from an external heat source. Various reflector and receiver designs for the Stirling dish engine have been developed over the years, including one-, two-, and four-piston designs for the engine itself (Stine and Diver 1994; Mancini 1997).

Although no utility-scale solar dish engine facilities are currently in operation in the United States,[68] development efforts are ongoing, including at DOE's Sandia National

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[65] Only a cursory review of relevant aspects of solar dish engine technology is provided here. For more information, see http://www.osti.gov/bridge/basicsearch.jsp. Accessed Jan. 5, 2009.

[66] In 1824, Nicholas Carnot first proposed his hypothetical external heat engine that was based on thermodynamic principles that control the behavior of a gas in a sealed system that is receiving heat from an external source (the Carnot cycle).

[67] As high as 1,452°F (790°C), according to DOE (2009).

[68] Recently, a PPA was negotiated between SES and San Diego Gas and Electric for power to be produced at a 750-MW facility composed of SES-designed Stirling dish engines. SES submitted an AFC for its facility to CEC on June 30, 2008 (SES Solar Two, LLC 2008). The entire AFC is available at http://www.energy.ca.gov/sitingcases/solartwo/documents/applicant/afc/index.php. Accessed Jan. 5, 2009.

Laboratories, in which a solar dish engine designed by Stirling Energy Systems (SES) recently attained the highest overall sunlight to electricity conversion efficiency of 31.25%.[69] Figure F.2.5-1 shows SES Stirling dish engines undergoing development and testing in Albuquerque, New Mexico. Figure F.2.5-2 shows the major components of the SES dish engine assembly.

F.2.5.1 Dish Engine Facility Components

F.2.5.1.1 Concentrators/Reflectors.[70] Early versions of the reflector used in solar dish engines were fabricated with conventional silver-backed glass mirrors. Now, reflectors are typically constructed of glass or plastic onto which aluminum or silver has been applied to either

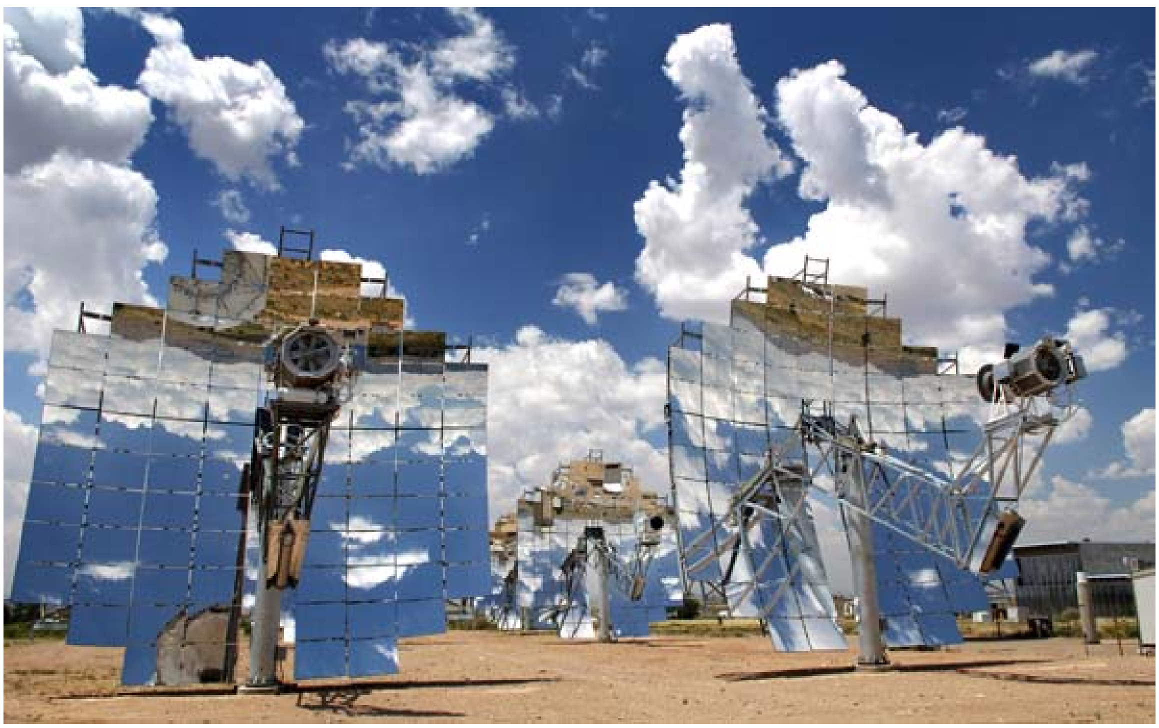

FIGURE F.2.5-1 Stirling Dish Engines at the Stirling Energy Systems Test Facility in Albuquerque, New Mexico (Credit: Randy Montoya. Source: Sandia National Laboratory. Available at http://www.sandia.gov/news/resources/releases/2008/solargrid.html. Accessed April 16, 2008)

[69] For information on research involving solar dish engine research, see http://www.nrel.gov/csp/troughnet/pdfs/2007/liden_ses_dish_stirling.pdf. Accessed Jan. 5, 2009.

[70] In this overview, the term “reflector” means a device that reflects (i.e., redirects) but does not concentrate incident sunlight. Conversely, a “concentrator” may comprise a number of reflecting devices that each, depending on orientation, reflect incident sunlight to a common point or line, thus causing a concentration or increase in solar insolation intensity at that point or along that line.

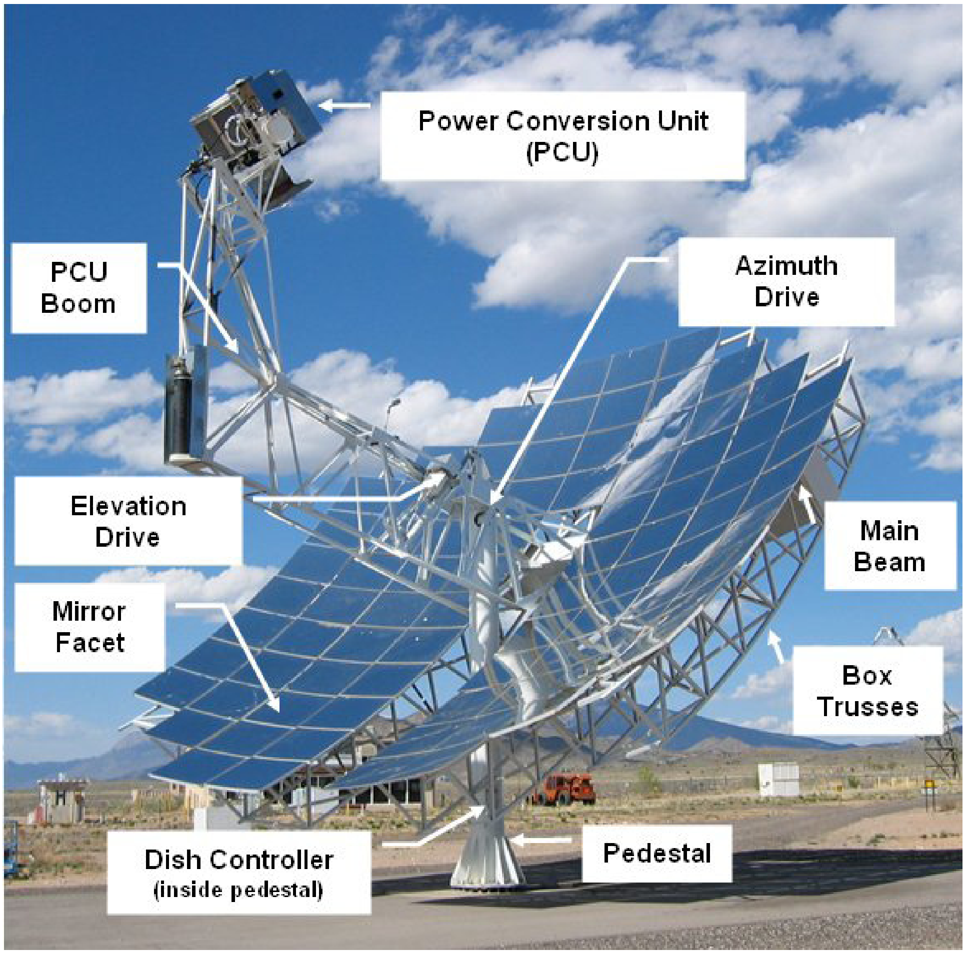

FIGURE F.2.5-2 Stirling Dish Engine Manufactured by Stirling Energy Systems (Reprinted with permission. Available at http://www.energy.ca.gov/sitingcases/solartwo/documents/applicant/afc/volume_01/MASTER_Section%201.0.pdf. Accessed July 17, 2008)

the back or front side (a back-surface or second-surface mirror). More recently, to further reduce production costs without sacrificing focusing accuracy, the parabolic shape of the reflector was attained through the use of multiple, spherically shaped mirrors rather than through a single continuous reflecting surface cast in the parabolic profile. In the latest advancement, the parabolic reflecting surface can be created through the use of flexible reflective membranes stretched across a rigid support and forced to assume the desired shape through the application of pressure or the creation of a vacuum between the reflective membrane and a second membrane stretched across the properly shaped support frame behind the reflective membrane.

Because the receiver is located in a fixed position relative to the reflecting surface, sunlight incident on the reflector will always be reflected precisely on the receiver. However, to attain maximum DNI capture efficiency, high-performing Stirling dish engine facilities capable of producing utility-scale power can be expected to have dual-axis tracking capability.

F.2.5.1.2 Receivers. The parabolic surface of the concentrator dish is capable of precisely reflecting incident sunlight to a point. However, because the sun's rays incident on the reflector are not precisely parallel (although far away, the sun is still not truly a point source), reflections onto the receiver are diffuse, with intensity decreasing exponentially with distance from the focal point of the reflector. Typically, the receiver is fitted with an aperture through which reflected sunlight enters the heavily insulated cavity, with the aperture being just large enough to admit most of the slightly diffuse reflected light. Reflected light strikes the absorber portion of the receiver that contains the working fluid (typically hydrogen gas). Minor variations in the receiver's design have been developed to ensure even heating of the working fluid with changing sunlight conditions. Because they operate at extremely high temperatures, receivers place special demands on design and material selection and can often represent a significant portion of the overall cost of a solar dish system. Further, the required high efficiency of the heat exchange that takes place at the receiver dictates precise fabrication controls and the use of materials that do not deform at high temperatures over time.

F.2.5.1.3 Stirling Engines. The Stirling engine is one of many designs that qualify as external heat engines, devices that can receive heat from an external source and convert it to mechanical work. The Stirling engine shares many functional similarities with the ICE. The power of an ICE derives from the rapid expansion of gases resulting from the controlled detonation of a gasoline (or diesel or ethanol)/air mixture in the engine's combustion chamber. In the Stirling engine, the power results not from any combustion of fuel, but from the heating and rapid expansion of a working gas by an external source of heat, in this case, the sun.

Although the thermodynamic efficiency of an external heat engine is theoretically very high, capabilities of real-world engines are limited by the temperature limitations of the materials used in their construction and by efficiency losses due to friction in the mechanical components of the engine. The Stirling engine operates at working gas temperatures between ≈1,100 to 1,470ºF (650 to 800ºC) and with projected overall efficiency as high as 40%.[71] Various designs have been advanced for the internal mechanical workings of the Stirling engine. The most typical design, a kinematic engine, involves a power piston that is acted upon by the expanding working gas being mechanically connected to a rotating output shaft, which in turn is connected to an integrated alternator or generator. Multiple piston arrangements are also possible. Figure F.2.5-3 provides a schematic of a Stirling-type engine most likely to be used in solar applications.

Although any gas, including air and nitrogen, can be used as a working gas in a Stirling engine and yield the same overall thermodynamic efficiencies, none can match the power-producing capability of hydrogen or helium. Hydrogen or helium is much preferred not only for high energy densities but also for desirable chemical and physical properties, such as low viscosities, high heat transfer capabilities, chemical and thermal stabilities under typical operating conditions, and thermodynamic efficiencies. Although hydrogen exhibits somewhat

[71] In February 2008, Sandia and SES jointly announced that a CSP research facility utilizing a Stirling dish engine recorded a new record for sunlight-to-electricity conversion efficiency of 31.25%, topping the previous (1984) record of 29.4%. See http://www.sandia.gov/news/resources/releases/2008/solargrid.html. Accessed Jan. 5, 2009.

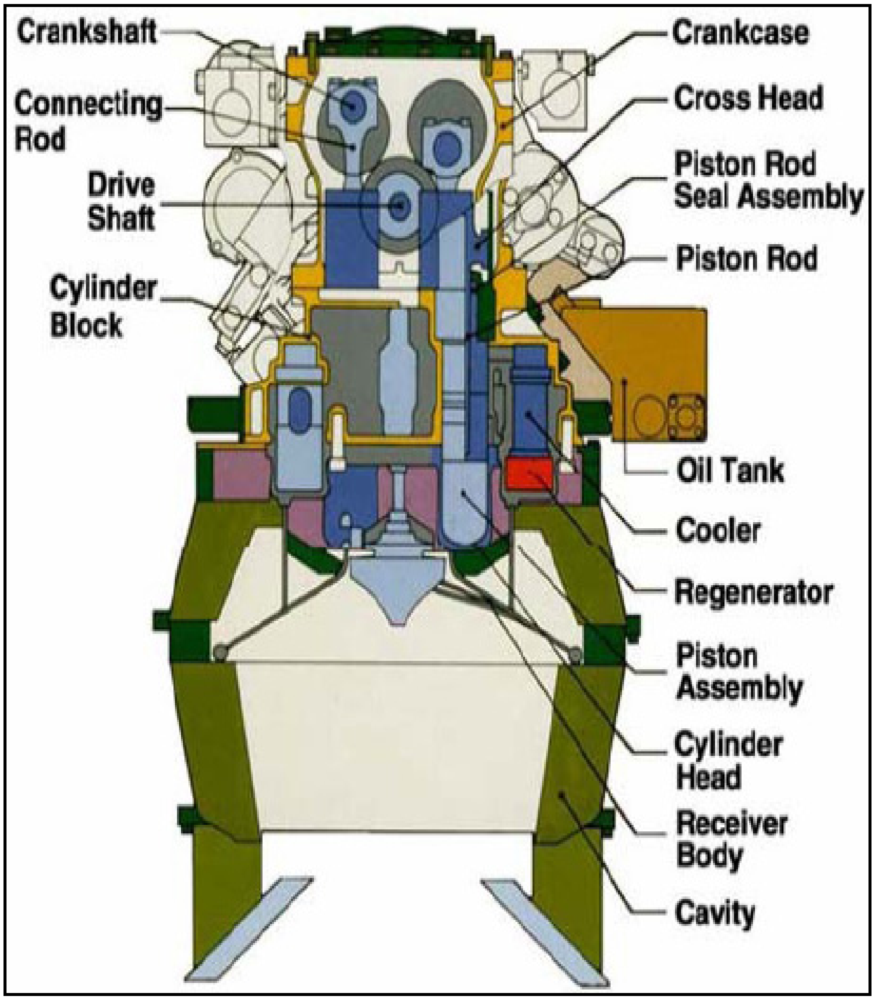

FIGURE F.2.5-3 Schematic of a Stirling-Type External Heat Engine (Courtesy of Stirling Energy Systems. Available at http://www.nrel.gov/csp/troughnet/pdfs/2007/liden_ses_dish_stirling.pdf. Accessed July 18, 2008)

better thermodynamic properties and results in overall better engine efficiencies, it creates more material incompatibility issues than does helium and introduces an additional safety hazard because of its flammable and explosive properties. More critical for hydrogen is its permeability through common metallic components and gasket materials, especially at the relatively high pressures (720 to 2,900 psi) (5 to 20 MPa) at which dish engines operate to maximize their power outputs. Operating experience to date suggests that hydrogen is likely to leak from its expansion chamber at a rate of less than 200 ft^3/yr (5.7 m^3/yr) (SES Solar Two, LLC 2008).[72]

[72] However, the amount of hydrogen working gas in an individual dish engine is quite small, and the engine is not considered to represent a significant fire or explosion hazard, nor would leakage of hydrogen from a Stirling engine constitute a significant fire or explosion hazard. In commercial applications, to ensure continuous operability, the engine would be supported externally by a compressed gas cylinder of hydrogen (most probably a 195-ft^3 [5.5-m^3] "k" cylinder) to replace any hydrogen that leaks from the receiver body.

However, permeability problems in future versions of the Stirling engine can be overcome by replacing components made of common steels with more expensive stainless steels, aluminum, or ceramics. Over the long term, hydrogen exhibits additional incompatibilities with engine components, causing metal embrittlement and ultimately component failure.

Although temperature extremes maximize the efficiency with which the working gas can convert heat energy into mechanical work, uncontrolled heat on the moving parts of the engine can result in premature wear, degradation of the lubricating oil, or wholesale failure. Consequently, high-efficiency Stirling engines are often also equipped with cooling devices. Typically, these consist of either a fan directing a flow of ambient air across critical engine components or the use of a circulating glycol-based, closed-loop coolant/external radiator system functionally identical to the cooling system used in an automobile.

Although waste engine heat must be managed, no Stirling dish engine hybrid designs have been advanced that would couple these engines with conventional fossil fuel-driven thermoelectric power-generating equipment. Likewise, no feasibility studies have explored harvesting the rejected heat from a Stirling engine to support cogeneration of process steam or as the first step in a coincident thermal storage system.

As with any mechanical device, Stirling engines are subject to wear and must receive regular maintenance and occasional refurbishment. The typical design basis for Stirling engines employed in solar dish systems includes a 20-year lifetime (40,000–60,000 hours of operation for engines operating at latitudes and areas ideal for solar technologies) before major refurbishment. Moving parts are subject to frictional wear similar to that which occurs in conventional ICEs. Lubricating oils must be changed periodically, although at somewhat greater intervals than oils in ICEs. Unless leakage occurs, the working gas is unchanged over time and needs neither servicing nor replacement over the expected useful life of the engine.

Unlike other CSP plants that produce steam to support a centrally located STG, each individual Stirling dish engine supports its own power conversion unit, which consists of an induction generator. The induction generator is fundamentally different from the synchronous generators typically found in STGs and CTGs. However, the induction generator is ideally suited for Stirling dish engine application because, unlike synchronous generators, the induction generator can produce power over a wide range of rotational speeds of its central shaft.

To date, no hybrid facilities have been proposed that would combine solar dish engines with other types of power-generating technologies in an effort to improve the dispatchability of the dish engine's power. Combining the solar dish engine with any technology utilizing a steam cycle would be impractical and offer very little advantage since the mechanisms by which such steam-based technologies produce electricity have little in common with the solar dish engine's power-generating technology. DOE is funding preliminary studies to investigate the feasibility of recovering heat from an operating Stirling-type dish engine for storage in a TES system by using thermally stable phase-changing salts.[73] As with all solar technologies, electrochemical energy

[73] For additional details on this as well as other ongoing TES R&D projects, see the DOE Solar Energy Technologies Program Web site at http://www1.eere.energy.gov/solar/pdfs/csp_funding_prospectus_2008.pdf.

storage through the use of deep cycle batteries is technically available for dish engine facilities; however, no practical applications of battery storage at dish engine facilities currently exist.

F.2.5.2 Utility-Scale Dish Engine Facilities

Various solar dish systems have been built around the world with a combination of heat engine and concentrator designs from various manufacturers. As noted above, no utility-scale solar dish engine facility is operational in the United States; however, there is a proposal to build the Imperial Valley Solar Project (formerly named SES Solar Two), in Imperial County, California, on both BLM-administered and privately owned land.[74] An AFC was submitted to the CEC on June 30, 2008 (SES Solar Two, LLC 2008). A supplement to the AFC was filed on June 12, 2009 (SES Solar Two, LLC 2009) that addressed changes to the water and hydrogen supply. The hydrogen supply for the project was changed from off-site reformation of natural gas to on-site production from electrolysis, which would reduce environmental impacts of hydrogen tank deliveries. In its application, the developer proposed to meet its water needs by using treated water from a nearby raw water canal. An estimated 33 ac-ft/yr (40 million m^3/yr) of water would be needed for mirror washing and drinking water. In the first set of data requests, the CEC asked for more information on the reliability of the proposed water supply and the source of backup water. In response to the data request, the CEC was provided with a supplement, which changed the primary water source to reclaimed water from a water treatment facility.[75]

F.2.5.3 Engineering Parameters and Resource Requirements for Dish Engine Facilities

The engineering parameters and environmental resource requirements of the proposed Imperial Valley facility include the following (Note: changes to project parameters that were provided in the June 2009 supplement to the AFC are reflected in brackets and italics, e.g., *[300 MW]*):

- Nominal capacity: 750 MWe developed in two phases (300 MW Phase 1 and 450 MW Phase 2)

- Total land area: 6,500 acres (26.3 km^2)

- On-site roads (maintenance access, paved): 25.2 mi (42.6 km); 138 acres (0.56 km^2)

- On-site roads (perimeter roads, unpaved): 11.2 mi (18 km); 16.2 acres (0.07 km^2)

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[74] Project approved. Updated information will be included in the Final PEIS.

[75] The complete AFC and documents related to CEC's review are available at http://www.energy.ca.gov/sitingcases/solartwo/documents/applicant/afc/index.php. Accessed Jan. 5, 2009.

- Main industrial area: 14.4 acres (0.058 km^2)

- Additional buildings: 14.4 acres (0.058 km^2)

- Main electrical substation: 5.2 acres (0.0^2 km^2)

- Construction
  - Laydown areas (2): 100 acres (0.4 km^2) and 11 acres (0.045 km^2)
  - Period (both phases): 40 months
  - Dish engine foundations: metal pipe, hydraulically driven into the ground or set in concrete, depending on extant soil and subsurface conditions
  - Workforce: varies from 101 to a maximum of 731 individuals

- Solar concentrator dish and engine
  - 25-kW capacity each
  - 38 ft (11.6 m) high, 40 ft (12.2 m) wide
  - Sunlight-to-electricity conversion efficiency: 31.25%
  - 12,000 solar dish engines in Phase 1
  - 18,000 solar dish engines in Phase 2

- Employment (fully developed 750-MW facility): 164 full-time individuals

- Water
  - Source: nearby canal *[reclaimed water from a wastewater treatment facility]*
  - Demands (mirror washing, miscellaneous industrial processes) *[hydrogen production]*: 33 ac-ft/yr (40,706 m^3/yr)
  - On-site storage (raw water for firefighting and industrial uses): 175,000 gal (662 m^3)

- Dielectric oil (transformers, switches, other electrical equipment): 50,000 gal (189 m^3)

- Lubricating oil (present in each Stirling engine, site-wide total): 108,333 gal (410 m^3)

- Hydrogen (present in each Stirling engine, site-wide total): 50,000 ft^3 (1,416 m^3) (On-site hydrogen generation system (by electrolysis) with distribution to each Stirling Engine [1,065 cf/h])

- Ethylene glycol coolant (present in each Stirling engine, site-wide total): 110,000 gal (416 m^3)

- Gasoline (storage tank for refueling on-site maintenance vehicles): 5,000 gal (19 m^3)

- Diesel fuel (storage tank for emergency generator): 5,000 gal (19 m^3)

F.3 PHOTOVOLTAIC (PV) TECHNOLOGIES

F.3.1 Overview of PV Technologies

F.3.1.1 PV Effect, Semiconductors, and the Solar Cell

PV technologies are fundamentally different from other technologies currently being used to produce electricity. The heart of PV technology is the solar cell that is capable of generating electricity by a physical process known as the photovoltaic effect. French physicist Edmund Becquerel discovered the photovoltaic effect in 1839 when, during experiments with electrolytic cells, he noticed that certain materials were capable of generating small amounts of electric current when exposed to sunlight. Materials exhibiting these unique properties are known as semiconductors. An overview of how semiconductors work is provided below to aid in understanding the function of solar cells and the overall design and power-generating capacity of PV systems.

Metals like copper and iron share a unique physical property: in their solid form, the bonding electrons (electrons in each atom's outermost shells) that hold the atoms together are relatively free to move about in the metallic crystalline lattice and are easily displaced by other electrons introduced into the lattice. Because electricity is the flow of electrons, this property allows metals to act as excellent conductors of electrical current. Atoms such as carbon, silicon, and germanium in their pure crystalline forms hold all their bonding electrons tightly in covalent bonds and resist or impede the flow of electrical current, acting instead as insulators. However, introducing minute amounts of impurities (called dopants) can result in dramatic changes in behavior. Silicon, the earth's second most abundant material (after oxygen), was one of the first materials used to manufacture semiconductors and still predominates as one of the major constituents of semiconductors produced today.

Two types of dopants can be introduced to create semiconductors: negative-type (N-type) and positive-type (P-type). Atoms such as phosphorus or arsenic have five electrons in their outmost shell. Crystallizing a mixture of silicon with a few atoms of phosphorus or arsenic results in a crystal lattice in which one bonding electron of each phosphorus or arsenic atom has nothing to bond with and is thus relatively free to be displaced. Because electrons have a negative charge, the material is known as an N-type semiconductor. Unlike pure silicon, this material conducts electricity, although not as efficiently as would a pure metal; thus it is referred to as a "*semi*conductor." Doping silicon with atoms having only three electrons in their outermost shell (e.g., boron or gallium) results in "holes" in the crystalline lattice (i.e., spaces that are deficient in electrons). Resulting materials are also capable of acting as semiconductors, not by being a source of electrons, but by accepting electrons introduced from outside the crystalline lattice. Such materials are identified as P-type semiconductors.

By themselves, neither N-type nor P-type semiconductors are very remarkable or have much practical application. However, in combination, they can produce electric current. The simplest configuration of a solar cell combines an N-type semiconductor with a P-type semiconductor, creating an interface or junction where the two meet. Some portion of the energy in sunlight striking this semiconductor pair is absorbed by the “extra” electrons in the N-type semiconductor that are not engaged in bonding. In their excited energy state, those electrons are free to escape from the semiconductor’s crystalline lattice and be replaced by other electrons from outside the N-type crystalline lattice. At the same time, the “holes” of electron deficiency in the P-type semiconductor are ready to accept electrons. In combination, an electric field is established at the junction of the semiconductor pair that can provide a flow of current when that field is connected to a load (i.e., an electrical device that can receive the flow of electrons to perform useful work). The N-type semiconductor provides a source of electrons to the load, while the “holes” in a P-type semiconductor realign to receive electrons from the load, thus completing the circuit (Figure F.3.1-1).

A wide variety of materials exhibit semiconductor properties. Among the many semiconductor materials that have been used for solar cells are silicon, copper indium diselenide, cadmium telluride, gallium indium phosphide, and gallium arsenide. Selection of the appropriate semiconductor material for solar energy applications is based on the semiconductor’s physical and electronic properties:

- Its degree of crystallinity, which controls its sunlight-to-electricity conversion efficiency;

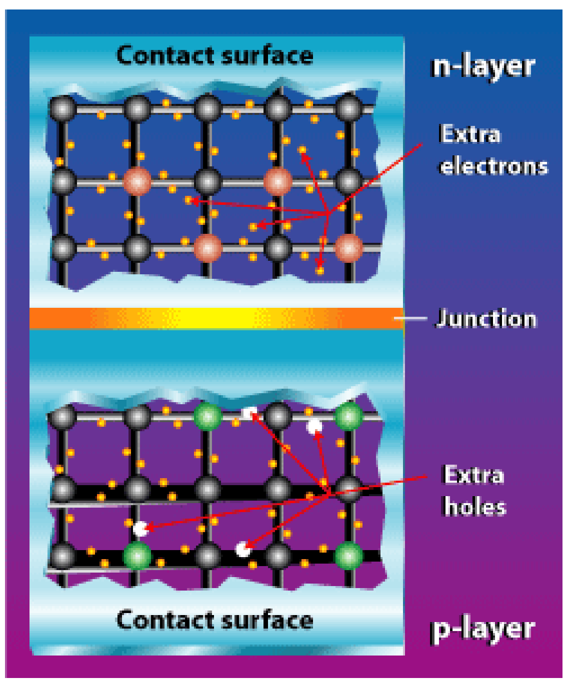

FIGURE F.3.1-1 Depiction of the PV Effect (Source: DOE/EERE. Available at http://www.eere.energy/gov/solar/ photoelectric_effect.html)

- The amount of sunlight that can be absorbed by a given thickness of material (its absorptivity);

- The range of wavelengths in the sun's light spectrum that can be absorbed (the band gap);

- More practical factors, such as the cost of production (primarily reflected in the cost and availability of raw materials, some of which are quite rare); and

- The complexity of the manufacturing process.

Band gap is the most critical and most influential property in the design of solar cells. Electrons in any semiconductor's crystalline lattice can exist only at discrete energy levels, with the lowest energy level available for any of an atom's bonding or valence electrons known as the valence band. The next higher energy level available, representing an electron capable of moving freely through its crystalline lattice, is known as the conductance band. Only electrons that exist in their conductance band energy level are available to produce electric current. The difference in these two energy levels is known as the band gap. Sunlight is composed of photons or packets of different energy levels. Only those photons having energy approximately equal to a semiconductor's band gap energy (Eg) can be absorbed by the crystalline lattice of a semiconductor to move valence electrons to their conductance band. Incident photons with less energy pass through the semiconductor materials without moving any valence electrons. Photons with greater energy also are absorbed and can move a valence electron, but the excess energy is essentially wasted; this energy is manifested not as additional electric potential but as heat, which, if not properly controlled, can significantly reduce the performance and longevity of a solar cell.

Solar cells composed of only one semiconductor pair (and thus only one band gap) have a practical limit to their conversion efficiency of no more than about 30%, since they can capture and efficiently use only a small portion of the sun's complete light energy spectrum. Under real-world conditions, solar cells made from single-crystal silicon can exhibit efficiencies of only about 10%, but such cells are relatively inexpensive to produce and so they are predominantly used in off-grid applications with relatively low power demands.[76]

The efficiency with which a solar cell can convert incident light energy to electrical potential also depends on whether its semiconductors have direct or indirect band gaps. Indirect band gaps use some of the incident energy to first create vibrations in the crystalline lattice, making only the remaining energy available for exciting a valence electron into its conductance band. Direct band gap semiconductors are, therefore, much preferred. They are typically composed of Group III elements of the periodic table, primarily aluminum, gallium, or indium combined with elements from Group V, such as nitrogen, phosphorus, or arsenic. Further, changing the relative proportions of these elements within the crystalline lattice allows the designer to create semiconductors with different Eg values.

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[76] However, recent advances in silicon solar cell technology have led to the development of thin-film silicon-based solar cells. Such solar cells are now being used in grid-connected, utility-scale PV systems.

The challenge for designers of utility-scale PV systems is to create a solar cell that absorbs the maximum amount of incident sunlight and converts it most efficiently to electrical potential. This is typically done by stacking semiconductors responsive to photons of different energy together in a multijunction solar cell “sandwich,” installing conductive metal grids above and below to carry current from and to the solar cell, and encasing the entire assembly in glass or transparent plastic to prevent contamination (e.g., from airborne dusts, oxygen, humidity), limit deterioration due to weather, and protect against incidental damage. In a typical arrangement, the semiconductor pair having the highest Eg is uppermost in the sandwich, followed by semiconductors with decreasing Eg values. In some cases, especially where the uppermost semiconductor is highly reflective (e.g., crystalline silicon), an antireflective coating is applied to the top of the cell to minimize reflection of incident light, which can reduce overall cell efficiency.

Solar cells composed of two semiconductors can theoretically capture as much as 50% of the incident solar flux (Wu et al. 2002). Researchers at DOE’s Lawrence Berkeley National Laboratory have identified a family of semiconductors composed of gallium indium and nitrogen, differing only in relative proportions of each element, that are photoelectronically active throughout the entire solar spectrum. A solar cell composed of all these semiconductors could theoretically capture as much as 86% of solar energy.

Although it is hypothetically possible to capture 100% of the sun’s light energy by simply stacking enough semiconductors together with Eg values collectively spanning the entire electromagnetic spectrum of sunlight, in practice there are limits. The reduced opacity of multijunction cells, optical losses due to reflection or refraction, as well as the complexity and cost of production have limited multijunction solar cells to a maximum of three or four semiconductor pairs and a real-world efficiency limit of 70%. Even so, multijunction solar cells greatly increase the overall energy-producing efficiency of a solar cell and are ultimately the choice for utility-scale PV systems. An example of a multijunction solar cell is depicted in Figure F.3.1-2.

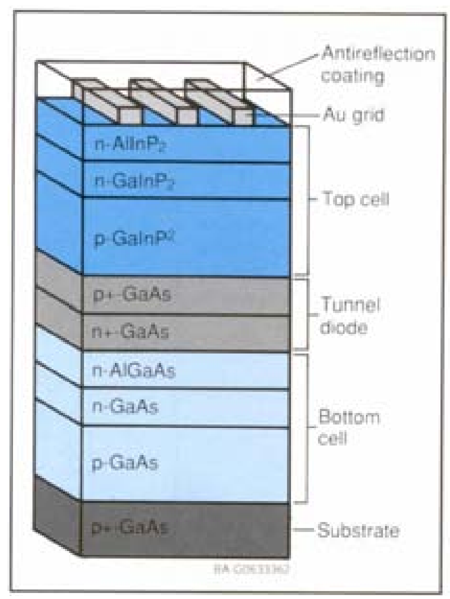

FIGURE F.3.1-2 Multijunction Solar Cell (Source: NREL. Available at http://www.nrel.gov/docs/legosti/old/16319.pdf)

F.3.1.2 Solar Cell Fabrication

Fabrication of solar cells involves a variety of complex processes, each requiring precisely controlled, scrupulously clean environments. Although fabrication activities are outside the scope of this PEIS because they would occur at remote manufacturing locations and not at the PV installations being considered, some background information is given here to assist in understanding the design and performance of PV facilities.

Solar cell fabrication is a major cost item for PV technologies. Semiconductors can be constructed of single crystals, semicrystals, polycrystals, or even amorphous materials and thin films. Each type offers unique advantages and disadvantages in both manufacturing and performance. In single-crystal semiconductors, all the atoms in the electrically active portion are precisely aligned. Although growing single-crystal cells is a delicate process,[77] their electrical performance is generally excellent. Semicrystalline or polycrystalline cells have active portions composed of many single crystals or grains, randomly arranged. Although such cells are less expensive to produce, this random arrangement of atoms creates potential for a reduction in electrical performance. In amorphous solar cells, atoms exist in totally random arrangements. Careful control of fabrication conditions can result in amorphous solar cells with good solar energy conversion efficiencies. Nevertheless, most amorphous solar cells, typically composed of silicon, have been used in low-power devices, and until recently, amorphous solar cells have not been considered for utility-scale PV systems. Now, many operating utility-scale PV facilities utilize amorphous thin-film silicon PV materials. Likewise, utility-scale PV facilities proposed for the United States would likely use thin-film amorphous silicon PV materials. (See Sections F.3.2.4 and F.3.3 for additional information on the types of solar cells being used or proposed for utility-scale PV facilities.)

Recent electronics industry advances have resulted in the production of thin-film semiconductors that also have PV applications. Thin-film solar cells comprise exceedingly thin layers of semiconductors stacked on top of each other. They can be made from a wide variety of semiconducting materials in both polycrystalline and amorphous forms. Production costs are dramatically reduced for thin-film solar cells. Because the entire thin film behaves monolithically, fabrication is substantially simplified over conventional solar panels that comprise many individual cells that must be precisely aligned and electrically interconnected to form a panel. The manufacturing process for thin-film solar cells is readily adaptable to creating thin films of various sizes and even building thin-film solar cells on flexible substrates such as thin plastic.

F.3.1.3 PV System Design Considerations

Regardless of their solar energy conversion efficiencies, individual solar cells (excluding thin-film solar cells) are quite small in their active area (i.e., the photoelectrically active portion exposed to sunlight) and produce minimal amounts of electricity (on the order of one or two watts at most). Consequently, applications of PV technology necessarily involve the use of many interconnected solar cells in a module. Various modules combine to make a solar panel, and panels are combined to create subarrays or arrays (Figure F.3.1-3). Modular design allows many arrangements of solar panels and relatively straightforward expansions of a PV facility's capacity. The nature of the solar cell used and the manner in which individual solar cells are interconnected allow the designer to attain critical electrical performance targets. Each solar cell produces only DC power. Connecting crystalline solar cells in series allows for the voltages

[77] Single crystals are typically grown in cylindrical shapes that are sliced to create wafers of various thickness (semiconductor material with poor absorptivity requires a thicker wafer to perform adequately), which may be further shaped into squares to allow for more efficient packing in a solar panel.

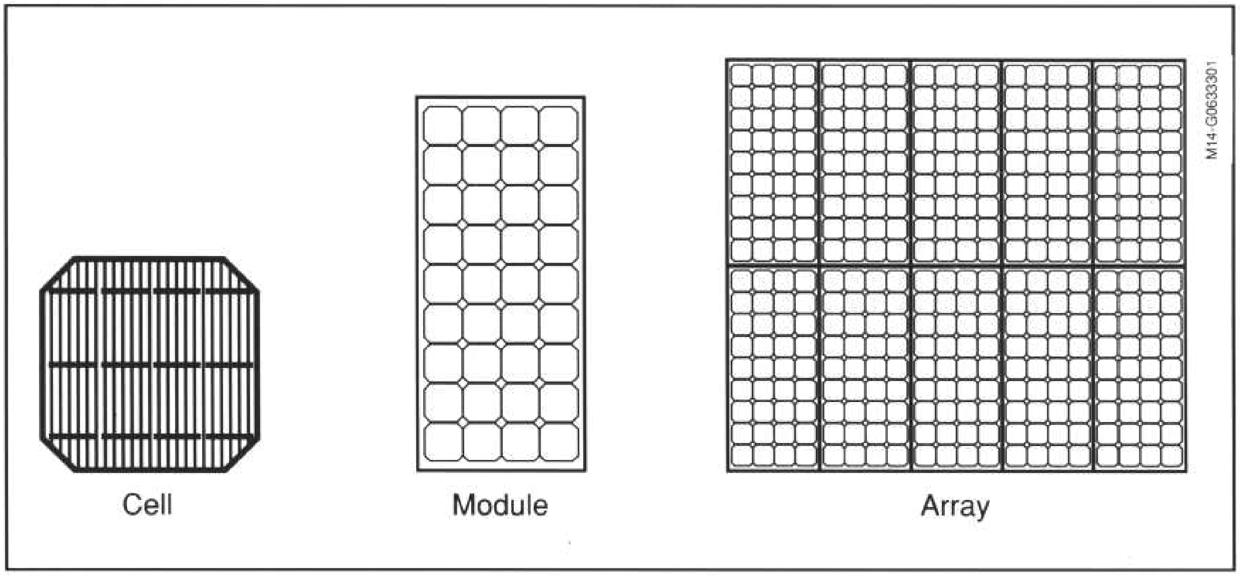

FIGURE F.3.1-3 PV Cells, Modules, and Arrays (Solar cells are incorporated into a module, and modules can be arranged in an array. Sometimes a panel of several modules is preassembled in a factory to reduce installation time and costs in the field.) (Source: NREL. Available at http://www.nrel.gov/docs/legosti/old/16319.pdf. Accessed Jan. 5, 2009)

produced by each cell to be additive while the current (in amperes) produced remains the same. Parallel connections allow for additive current across the interconnected cells without an increase in voltage.

For large PV systems connected to the grid, both voltage and current need to be controlled; thus both methods of interconnection are used. Cells within a module are connected in series to increase voltage, while modules in a panel are interconnected in parallel to increase amperage or in series to increase voltage. In practice, the method of interconnection is critical to overall performance. Reliability over time and over a wide range of environmental conditions, especially changes in ambient temperature, increases the criticality of cell interconnections.

Thin-film solar cells offer a distinct advantage with respect to reliable connectivity. While other solar cells are interconnected with metallic grids or wires, thin films convey their current through thin layers of electrically conductive metal oxides such as tin oxide, indium tin oxide, or zinc oxide. All oxides used for this purpose can be easily applied during fabrication by the use of essentially the same molecular deposition methods as used to deposit the thin films of semiconductor materials. In addition to overcoming many of the difficulties in installing and maintaining solar panels interconnected by metal grids, thin-film oxide conductors are all highly transparent to incident light (i.e., their presence does not affect overall solar cell performance by blocking, reflecting, or refracting incident light) and offer very little resistance to the flow of current. Once installed on their substrate as a continuous film, thin-film solar panels can create individual solar cells, interconnected (through the oxide film) in the manner necessary to meet module voltage and current requirements.

A wide variety of PV materials have been identified as having potential application in solar cells. Manufacturing costs and worldwide availability of raw materials used in the production of compound semiconductors, combined with the relatively inexpensive production costs and widespread availability of silicon-based semiconductors, have been major controlling factors in the type of PV material applied in photoelectric facilities. In 2000, the distribution of photocell material in use included polycrystalline silicon, 47.54%; single-crystal silicon, 35.17%; amorphous silicon, 8.30%; ribbon silicon, 3.50%; thin-film silicon, 0.26%; and others, less than 1% (Summers and Radde 2004).

Efficiency of conversion of photons to electricity has steadily increased without concomitant increases in costs. The use of concentrating lenses in combination with compound semiconductors and precise dual-axis tracking has resulted in observed efficiencies of 32.3% (Summers and Radde 2004). Using a triple-junction solar cell composed of gallium indium phosphide and gallium indium arsenide to split the solar spectrum into three equal parts, researchers at NREL reported a 40.8% efficiency concentrator cell in 2008 (NREL 2008b).

Overall efficiency still varies considerably among candidate PV materials. Most PV modules sold today are single-crystal or polycrystalline silicon. Likely semiconductor materials for future grid-connected central PV facilities include thin-film cells composed of both amorphous and polycrystalline silicon as well as a wide variety of compound semiconductor materials such as cadmium telluride (CdTe), copper indium gallium diselenide, and materials constructed of alloys of Group III elements (e.g., aluminum, gallium, and indium) and Group V elements (e.g., nitrogen, phosphorus, and antimony).

The candidate PV materials that will be deployed in large utility-scale PV systems will be determined by a combination of many factors, including module efficiency, manufacturing costs, reliability, installation costs, and O&M costs. The efficiency of the PV cells is important, but it will not be the only factor under consideration.

F.3.2 Types of PV Technologies and Facilities

PV technologies can be placed in two types of systems, flat-plate systems and concentrating systems. Flat-plate systems all utilize solar modules whose designs allow sunlight to directly strike the solar cells, without benefit of any light-concentrating or -focusing device. They are further differentiated by the orientation of their solar modules as being either fixed or tracking. CPV systems use concentrating or reflecting devices to effectively increase the amount of light energy that strikes the high-performance solar cells. CPV systems also require the use of tracking devices to take full advantage of their high-performance solar cells. Solar cell materials and design, and the design and orientation of solar modules and arrays, are the chief differentiating factors among PV facilities. Beyond these factors, the components that compose the remainder of the PV facility (the balance of the system) are quite similar across all PV technologies.

F.3.2.1 Flat-Plate Systems (Nonconcentrating)

In the simplest PV systems, the solar cells are arranged in flat modules or flat plates and no other components otherwise concentrate the sunlight before it strikes the solar cell. The flat modules are placed in a fixed position to capture the maximum amount of sunlight, typically pointing the module to the sun's expected midday position and adjusting the tilt of the module to maximize the annual energy production.[78] Once a tilt angle is established, the module's position does not change throughout the lifetime of the facility. The tilt angle can be chosen to maximize the annual energy production or for a specific season such as summer. The costs for design, construction, and maintenance of fixed, flat-plate systems are typically the lowest of all PV system designs.

In more sophisticated systems, flat-plate modules are mounted on motorized devices that track the sun's movement across the sky on one or two axes. Single-axis tracking follows the sun's diurnal path (i.e., east to west over the course of a day), and dual-axis tracking additionally follows the sun's seasonally changing paths (i.e., changes to the sun's altitude above the horizon over the course of a year). Tracking capability adds complexity and cost to the mounting devices and to the systems that control them. Maintenance costs also increase over fixed flat-plate PV systems. However, more energy can be produced, which should offset the additional costs of a tracking system.

Not all tracking flat-plate PV systems utilize dual-axis tracking. Changes in the sun's seasonal position are most pronounced in the northern latitudes of the northern hemisphere. For PV facilities located in southern latitudes, the seasonal difference in the sun's altitude is slight, and the loss of insolation due to divergence of the module's tilt angle from a precisely perpendicular orientation to incident light does not justify the cost and complexity of dual-axis tracking. Figure F.3.2-1 shows both a fixed-tilt flat-plate PV system with single-axis tracking (foreground) and a dual-axis tracking CPV system.

Also shown in Figure F.3.2-1 is the typical height difference between a fixed-tilt nonconcentrating PV system and a dual-axis tracking CPV system. A horizontal single-axis tracking flat-plate PV system is about the same height as a fixed flat-plate system (10 ft [3 m] or less).

F.3.2.2 Concentrating PV (CPV)

CPV systems differ from flat-plate PV systems by integrating a light-concentrating or light-focusing device ahead of the solar cells to effectively increase the amount of sunlight striking the photoelectrically active portion of the solar cell without actually increasing its area. If the amount of the sun's energy reaching a simple solar cell is defined as "one sun," then equipping that solar cell with a 10-fold concentrating device means that "10 suns" are now reaching the solar cell (Figure F.3.2-2). And because the conversion efficiencies of most solar

[78] In practice, both directly incident sunlight and diffuse sunlight (i.e., reflected from clouds, the ground surface, and surrounding objects) are captured by nonconcentrating flat panel PV systems.

FIGURE F.3.2-1 A Utility-Scale Flat-Plate PV System at the Prescott, Arizona, Airport Operated by Arizona Public Service Company (This system incorporates flat-plate nonconcentrating solar panels [foreground] and concentrating flat-plate solar panels [background].) (Credit: Arizona Public Services; Source: NREL 2010)

cells actually increase with increasing intensity of incident light (at a fixed temperature), the cell is now capable of producing slightly more than 10 times the amount of electricity. With the use of various devices that provide reflection and refraction, sunlight can be concentrated along a line or at a point (see Figure F.3.2-3) by means of a Fresnel lens.[79] A highly reflective parabolic surface can concentrate light along a line, while both mirrors lining the inside surface of a dish and a relatively inexpensive Fresnel lens can serve as point concentrators and, when arranged in a row, as line concentrators.

With current technology, as much as 300-fold increases in insolation (referred to within the industry as the concentration ratio) reaching the solar cell can be accomplished. Three concentration regimes are generally recognized: low concentration (concentration factors from 2 to 10 suns), medium concentration (from 10 to 60 suns), and high concentration (more than 100 suns) (Goetzberger and Hoffmann 2005). Although individual solar cells in a flat plate can be modified by fitting each with a concentrating lens to create CPV systems, space and cost

[79] The Fresnel lens was invented by French physicist Augustin-Jean Fresnel and was first used in lighthouses in the early 1800s. The desirable optical characteristics of the Fresnel lens, a very large aperture and relatively short focal length, are consequences of its being constructed of numerous curved lenses arranged in concentric circles (or Fresnel zones) rather than being constructed in one piece. Each zone is at a slightly different angle to incident light so that all zones focus light to the same point, resulting in magnification of the light's intensity. Advantages of such construction include comparatively low cost of production (compared to conventional one-piece lenses) and substantial weight savings when the lenses are made of acrylic rather than glass.

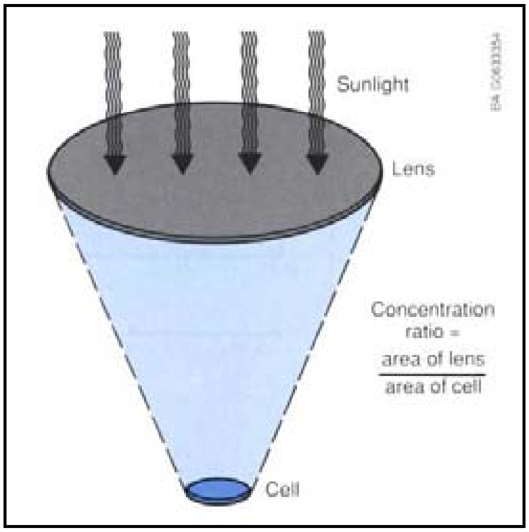

FIGURE F.3.2-2 Concentration Ratio for a Circular Lens (The ratio can also be defined for a linear parabolic reflector or a circular parabolic reflector. Greater tracking accuracy is required for higher concentration ratios.) (Source: NREL. http://www.nrel.gov/docs/legosti/old/16319.pdf. Accessed Jan. 5, 2009.)

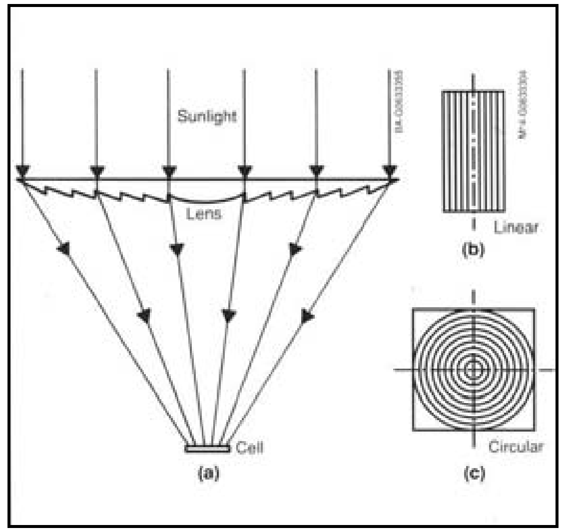

FIGURE F.3.2-3 Fresnel Lens Concentrator (Fresnel lenses can be circular or linear.) (Source: NREL. http://www.nrel.gov/docs/legosti/old/16319.pdf. Accessed Jan. 5, 2009)

considerations have resulted in the development of various other configurations. These include using a common concentrating device in a convex orientation above a conventional flat-plate solar module, lining the surface of a concave dish with reflecting devices and placing the solar cell at the focal point of the dish, or placing solar cells at the top of a tower that is surrounded by reflecting devices arrayed on the ground, all aiming at the solar cells.

A variety of concentrating devices provide a wide range of power magnification, from as low as 10- to 20-fold increases to well over 500-fold.[80] However, CPV systems must use high-performance cells to capture higher degrees of sunlight concentration. Typical choices include cells constructed of alloys of Group III elements (e.g., aluminum, gallium, and indium) and Group V elements (e.g., nitrogen, phosphorus, and antimony), along with crystalline silicon. Such cells have exhibited solar energy conversion efficiencies of 28% with direct solar irradiance and as high as 36% when incorporated into CPV systems (Dahle et al. 2008). Further, alignments between incident light, the concentrating lens, and the solar cell are critical in CPV systems because even a slight misalignment will likely result in a precipitous drop in system performance. CPV systems, therefore, must use dual-axis tracking to realize their full potential throughout daylight hours and throughout the year.

[80] At the current stage of CPV technology development, a 500× magnification is the practical limit. That degree of magnification requires the PV panel to be supported by an extremely precise tracking device to realize its fullest potential.

NREL, together with its commercial and academic partners, is currently conducting research on CPV technology. The High-Performance PV Project[81] has already demonstrated a high-performance CPV solar cell with a sunlight-to-electricity conversion efficiency of 37.3%. Replacing nonconcentrating solar panels composed of 25% efficient silicon cells with these high-performance CPV cells can result in an energy production increase of 50%, which may equate to a reduction in energy costs of as much as 33%. Research is still needed, however, to lower the cost of CPV cell production while increasing its reliability and efficiently and addressing some coincident negative effects of sunlight concentration, such as increased heat.

Figure F.3.2-1 showed a PV facility installed at the Prescott, Arizona, airport that uses both flat-plate PV and CPV technologies. Figures F.3.2-4 and F.3.2-5 show flat- plate and dish configurations of CPV, respectively, while Figure F.3.2-6 shows a CPV system that uses parabolic trough line concentrators.

Although CPV systems can produce as much as 30% more energy than fixed flat-plate systems having the same total illuminated area (Dahle et al. 2008), primarily because of the tracking feature and not necessarily the concentrating feature, there are drawbacks. Both production costs and maintenance costs are higher for CPV than for conventional flat-plate PV. The necessary commitments to high-performance (and more expensive) solar cells and precise dual-axis tracking also add to development and installation costs and introduce additional maintenance obligations throughout the facility's life. High-performance solar cells provide no tangible advantage over less expensive counterparts unless their performance is matched by the

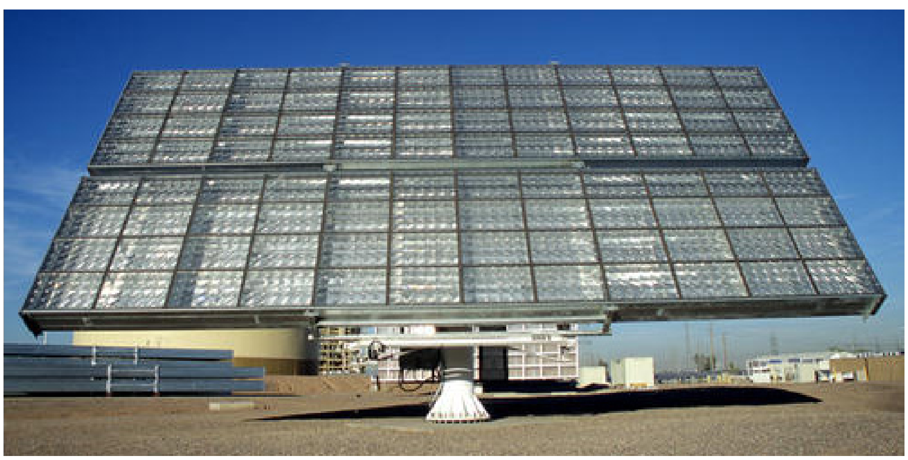

FIGURE F.3.2-4 Fresnel Point Concentrators Positioned above Flat-Plate PV Solar Panels at Arizona Public Service's Solar Test and Research (STAR) Center, Tempe, Arizona (This unit can produce 20 kW of electricity.) (Credit: W. Timmerman. Source: NREL. Photo #08992. Available at http://www.nrel.gov.data/pix/searchpix.html. Accessed April 15, 2008)

[81] Additional information on the High-Performance PV Project is available at http://www.nrel.gov/pv/highperformancepv/. Accessed Jan. 5, 2009.

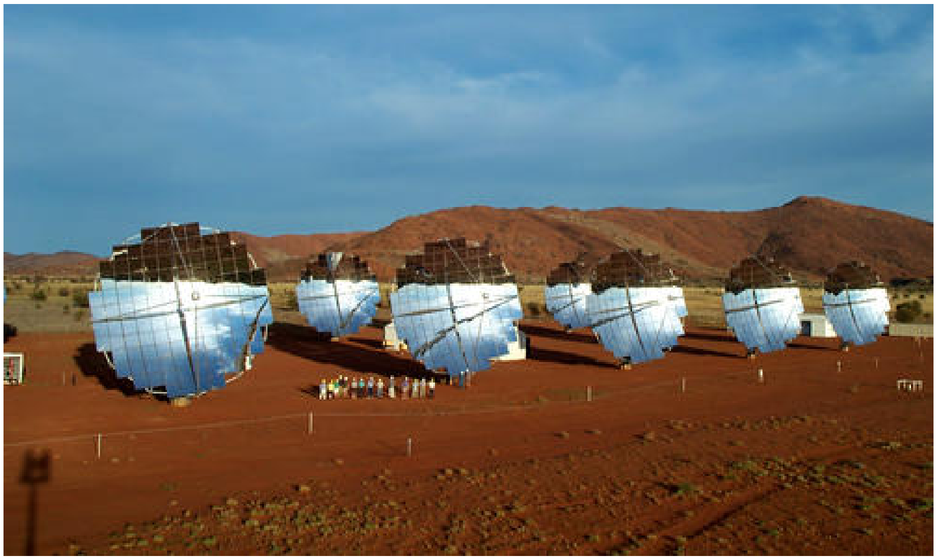

FIGURE F.3.2-5 25-kW CPV Dish at Alice Springs, Australia (The solar panels are positioned at the focal points of each of the dishes by four support arms that also serve to provide support for electrical cables and water lines for cooling jackets.) (Credit: R. McConnell. Source: NREL. Photo #13736. Available at http://www.nrel.gov/data/pix/Jpegs/13736.jpg. Accessed April 15, 2008)

FIGURE F.3.2-6 CPV System Using Parabolic Trough Line Concentrators (This 480-kilowatt-peak (kWp) research facility is operated by the University of Madrid, Spain.) (Source: NREL. Photo #13744. Available at http://www.nrel.gov/data/pix/. Accessed Jan. 5, 2009)

quality of the reflecting mirrors or the concentrating lenses that deliver sunlight to them. Both mirrors and lenses must be kept clean to perform at their best, which is often a significant commitment in desert areas that have periods of high concentrations of airborne dusts.[82]

Concentrating sunlight also concentrates heat. Solar cells are not responsive to heat and do not convert heat to electricity. Instead, the heat must be controlled to prevent solar cell deterioration or loss of solar cell performance, reliability, and longevity. Higher levels of light magnification may therefore require more aggressive cooling than simple inexpensive passive systems can provide. As magnification and heating rise, so will the cost and complexity of the cooling system that are required.[83] Cooling system designs can have tremendous variation and include a variety of HTFs.

Concentrators have been applied in only a few utility-scale systems. One such proposed facility, the Victorian Project in Australia, will have a 154-megawatt-peak (MWp)[84] capacity (see Section F.3.2.4). A number of smaller, non-utility-scale CPV projects have been installed, many of them by a company called Solar Systems in Australia. These systems range in capacity from 40 kWp to 288 kWp, and most of them augment local diesel generation (Kinsey et al. 2006; Solar Systems undated a–d). One small CPV system with a capacity of 75 kWp has been installed at the Clark Generating Station, a 740-MW gas-fired power plant in Nevada (Edwards 2006).

F.3.2.3 PV Facility Balance of System

The basic balance of system components for a typical PV facility and their function are shown in Table F.3.2-1. The most critical component from the perspective of the transmission grid operator is the power conditioning system (PCS). PV cells produce DC electricity. That power must be converted to AC and conditioned before a connection from the PV facility can be safely made. One item of PCS equipment unique to PV facilities is a DC-AC inverter that converts the initially produced DC current to AC. Modern-day inverters use solid-state technology and typically operate at efficiencies higher than 90%. The remaining equipment in the PCS is functionally identical to power conditioning and management equipment found at any thermoelectric power plant but has special design features to accommodate the unique character

[82] Over the long term, abrasive airborne particulates can also damage the surfaces of mirrors and lenses, further reducing their performance.

[83] Passive cooling systems may be as simple as adding cooling fins at strategic locations to enhance the solar cell assemblies' ability to dissipate heat to their surroundings through radiation cooling. Active cooling systems can range from forced air flow across the solar cell assembly to simple water circulation between the solar cell assembly and a remote heat exchanger to more sophisticated systems using HTFs such as synthetic oils, ethylene glycol solutions, brines, conventional refrigerants (including ozone-depleting chemicals), or HTFs with even higher heat exchange potentials, such as anhydrous ammonia. Active cooling systems also introduce additional maintenance costs as well as the potential for release of coolants to the environment in the event of system failure.

[84] Megawatt-peak (MWp) and kilowatt-peak (kWp) are measures of the peak output of a given PV system.

TABLE F.3.2-1 Balance of System Components for PV Facilities

Component	Function	Notes
Electrical cables	Deliver power from individual PV module assemblies to a PCS within the facility and then to a grid.	Often buried below ground for security against storm damage.
Solar module mounting assemblies (fixed plate)	Secure solar modules at the appropriate angle to incident sunlight, sometimes also including line-concentrating or point-concentrating devices.	Often of complex designs to adjust for land surface slopes and irregularities; constructed of suitable materials to resist the vagaries of weather over the lifetime of the facility.
Solar module tracking assemblies	Change the orientation of the solar module assembly over the course of the day and year to maximize incident solar radiation (typically using electric motors or hydraulic systems).	Both single-axis and dual-axis tracking systems are used. Trackers require firm footings (piles, pylons) in the ground.
Cooling system/ passive/air cooled	Dissipate heat from solar module assemblies using convection cooling.	Typically necessary only on CPV systems. Not needed in all locations.
Cooling system/ active/air cooled	Dissipate heat from solar module assemblies using forced air flow by means of electric fans.	Typically necessary only on CPV systems.
Cooling system/ active/liquid cooled	Dissipate heat from solar module assemblies using liquid coolants circulated between the solar panel assembly and a remote heat exchanger by electrically powered pumps.	May be necessary for CPV systems with high light-concentration ratios.
SCADA systems	Remotely monitor system performance, control solar module assembly tracking features (when equipped), engage or disengage hybrid system components, monitor power conditioning, and make adjustments to operating parameters in response to upset or changing conditions.	Typically consisting of various solid-state monitoring and control devices, remotely controlled switches and motors, and communication systems (telephone, optic cable, radio, microwave) connecting the facility with a remote control center.
Power conditioning equipment (PCS)	Convert the DC electricity produced at the solar modules to AC with inverters. Transformers are used to step up the voltage, and electronics are used to synchronize the phase of the current before connecting it to the transmission grid.	Typically, many strategically located PCSs would be required. Each PCS would also be equipped with various switches, capacitors, and other electrical devices designed to protect the reliability of the transmission grid.

TABLE F.3.2-1 (Cont.)

Component	Function	Notes
Module cleaning system	Keep surfaces of the solar cells free of dust. Systems can be manual (e.g., spraying from water trucks) or built in.	To avoid scale build-up on the hot PV module's surface, water used for cleaning must be demineralized before use. Recovery of wash solutions may or may not be practical, depending on arrangements of the PV modules.
Grounding system	Provide personnel safety, lightning protection, reduction of static charge buildup, and electrical surge protection.	Typically composed of strategically placed copper grounding rods or metallic grounding nets buried beneath the ground surface.
Drainage system	Remove rain and cleaning water from site via trenches and/or pipes.	

of the power. Importantly, all PCSs are equipped with devices that can sense grid-destabilizing events and faults and automatically disconnect the PV facility from the grid.

F.3.2.4 Utility-Scale PV Facilities

Utility-scale PV power plants are a new and rapidly developing technology. Among the 25 largest operational plants worldwide, ranging in capacity from 5 to 20 MWp, only six were connected to their respective power grids before 2007. Total installed capacity increased from 186 MWp in 2006 to 489 MWp at the end of 2007. Lenardic (2008a) summarizes information about PV power plants greater than 200 kWp. Seventy percent of these plants are ground mounted; 29% roof mounted; and 1% integrated into buildings. Europe has 81% of the worldwide solar power capacity; the United States, 14%; Asia, 4%; and the rest of the world, less than 1%. The industry is developing rapidly, and the United States, Germany, Spain, Italy, and Korea all have utility-scale projects under construction.

Table F.3.2-2 provides information about utility-scale PV power plants with a peak capacity of at least 10 MWp. Plants scheduled for completion in 2008 or beyond are included in the table along with several proposed facilities. Except for the proposed Victorian Project (Australia), which will use CPV technology, all the listed plants use flat-plate PV systems.

In recent years, interest in utility-scale PV in the United States has risen sharply, and numerous utility-scale PV facilities have been proposed, most in southern California. One such facility has been proposed to be built on the Carrizo Plain in San Luis Obispo County, California, by Topaz Solar Farms, LLC (formerly a wholly owned subsidiary of OptiSolar, Inc., a California-based manufacturer of thin-film amorphous silicon PV modules, now owned by First Solar). It is one of a number of similarly sized facilities proposed for construction in various

TABLE F.3.2-2 Summary Information for Existing and Proposed Utility-Scale PV Plants

Plant Name	Location	Capacity (MWp)	Annual Power Produced (MWh)	Plant Area acres (km^2)	Solar Modules Number	Solar Modules Area (m^2)	Notes[a]
Victorian Project[b]	Australia	154	270,000	NA	62,976	NA	• Proposed • 500× solar concentration technology • Components: 19,250 heliostats, 246 receivers • Phase 1 commissioning expected in 2010; phase 2 in 2013
Kings River Conservation District Solar Plant[c]	California	80	NA	NA	NA	NA	• Proposed in Fresno County • Construction over 3 yr: 10 MWp in 2009, 30 MWp in 2010, 40 MWp in 2011
Topaz Solar Farm	California	550	NA	6,200 (25)	NA	NA	• Proposed in San Luis Obispo County • Construction scheduled to begin in 2010 • Thin-film silicon cells • In a June 2009 revision to the CUP, the plant area was changed to 5,200 acres (21.5 km^2)
Moura Energy Station[d]	Portugal	62	88,000[e]	321 (13)	>376,000	130 ha (320 acres)	• Under construction • Two-stage construction: 42 MWp in 2008, 20 MWp in 2009 • Mounting for first phase: 190,000 panels (32 MWp) fixed and 52,000 (10 MWp) on single-axis trackers

1

TABLE F.3.2-2 (Cont.)

Plant Name	Location	Capacity (MWp)	Annual Power Produced (MWh)	Plant Area acres (km^2)	Solar Modules: Number	Solar Modules: Area (m^2)	Notes[a]
Solarpark Waldpolenz[f]	Germany	24	40,000	272 (1.1)	550,000	400,000	• First year of operation 2007; planned expansion in 2009 will increase plant capacity to 40 MWp • Thin-film modules, no tracking • Operating lifetime of at least 20 yr and probably 30–40 yr
Parque Fotovoltaico Abertura Solar[g]	Spain	23	NA	440 (1.8)	NA	NA	• Planned start of operation: 2008 • 2,000 h/yr sun • Very flat land • 11-month construction time • 200 individual 100-kW plants each with 600 PV panels, one tracker, one inverter, one transformer, and additional infrastructure • 200 single-axis trackers: 5,000 tons of galvanized steel, 26,000 holes drilled, 22,222 yd^3 (17,000 m^3) of concrete for vertical supports • Rainwater drainage: 7.5 mi (12 km) of channels/trenches and 0.2 mi (350 m) of piping • 14×10^6 L (16,293 m^3) of water storage for fire control • 48,390 ft^2 (4,500 m^2) of revegetation • Control center and substation occupying 3,230 ft^2 (300 m^2)

TABLE F.3.2-2 (Cont.)

Plant Name	Location	Capacity (MWp)	Annual Power Produced (MWh)	Plant Area acres (km^2)	Solar Modules Number	Solar Modules Area (m^2)	Notes[a]
Parque Solar Hoya de Los Vicentes[h]	Spain	23	42,000[e]	247 (1)	120,000	NA	• Planned start of operation: 2008 • Continual breeze keeps panels cool
Solarpark Calaveron[i]	Spain	21	40,000	247 (1)	96,000	NA	• Planned start of operation: Jan. 2008 • Polycrystalline modules
Planta Solar La Magascona[j]	Spain	20	NA	247 (1)	120,000	NA	• Planned start of operation: 2008 • 200 100-kW solar plants each with 600 PV panels • Operating lifetime of 30 yr
Solarpark Beneixama[k]	Spain	20	30,000	124 (0.5)	100,000	NA	• Planned start of operation: Sept. 2007 • Polycrystalline modules • 1-yr construction time; 80 employees at different times
SinAn Power Plant[l]	Korea	19.6	27,000	400 (1.6)	109,000	600,000	Planned start of operation: May 2008
Almeria PV Park[m]	Spain	15.4	24,000	NA	91,000	300,000	Under construction
Nellis Air Force Base[n]	Nevada	14.2	30,100	141 (0.57)	72,416 200-W modules 5,891,328 cells	NA	• First operation: Dec. 2007 • 26 weeks construction time; 200 workers • 5,821 trackers, 18 transformers, 54 inverters, 1,051 mi (1,691 km) of power cable • See text for additional information

TABLE F.3.2-2 (Cont.)

Plant Name	Location	Capacity (MWp)	Annual Power Produced (MWh)	Plant Area acres (km^2)	Solar Modules Number	Solar Modules Area (m^2)	Notes[a]
Planta Solar de Salamanca[o]	Spain	13.8	NA	89 (0.36)	70,000	NA	• First operation: Sept. 2007 • Three separate arrays on-site
Solarpark Lobosillo[p]	Spain	12.7	NA	NA	83,000	NA	• First operation: Sept. 2007 • First phase of 60-MWp project • 140 100-kW systems
Parque Solar Fotovoltaico Villafranca[q]	Spain	12	NA	NA	NA	NA	• Planned start of operation: 2008 • 13 “solar farms or gardens,” including the largest, Huerta Solar Monte Alto, below • Each park has multiple owners and contains 5−11 kW individual panels and trackers
Solarpark Gut Erlasee[r]	Germany	12	14,000	77	NA	NA	• First year of operation: 2006
Serpa PV Power Plant[s]	Portugal	11	NA	60	52,000	NA	• First operation: March 2007 • On south-facing hillside • Single-axis tracking • At least 25-yr lifetime • 7-month construction period

TABLE F.3.2-2 (Cont.)

Plant Name	Location	Capacity (MWp)	Annual Power Produced (MWh)	Plant Area acres (km^2)	Solar Modules Number	Solar Modules Area (m^2)	Notes[a]
Solarpark Pocking[t]	Germany	10	10,750	26	57,600	75,000	• First operation: Dec. 2005 • Single-axis tracking • 3 separate systems at locations in close proximity • Individual 1.67 MWp solar modules • 4 rows of panels with aluminum supporting structures; substructure length of about 10.3 mi (16.5 km) • Panel foundations fixed with 8,112 “earth bolts” • 24 400-kVA inverters and 4 1,600-kVA inverters
Parque Solar de Zuera[u]	Spain	9.9	NA	52	47,000	NA	• Planned start of operation: 2008 • 90 individual 110-kWp solar modules Approximately 350 construction workers
Huerta Solar Monte Alto[v]	Spain	9.5	14,000	51	52,706 modules	NA	• First year of operation: 2006 • Built on hilly terrain • 899 solar structures, 864 with automated solar tracking, remainder fixed and adapted to topography • 18.6 mi (30 km) of ditches for electrical conduits, 55.9 mi (90 km) of pipes, 7,843 yd^3 (6,000 m^3) of concrete, 3.9 mi (6.3 km) of bore holes (number not specified) for trackers

TABLE F.3.2-2 (Cont.)

Plant Name	Location	Capacity (MWp)	Annual Power Produced (MWh)	Plant Area acres (km^2)	Solar Modules Number	Solar Modules Area (m^2)	Notes[a]
Planta Solar Villa de Canas[w]	Spain	9.5	NA	NA	NA	NA	• Planned start of operation: Feb. 2008 • 7 months to construct

[a] Information in this table was compiled in mid-2008 and reflects project status at that time.

[b] Solar Systems (undated a).

[c] RED (2008a).

[d] The Guardian (2005); Now Public (2008).

[e] MEI (2007).

[f] juwi group (2007).

[g] RED (2008b).

[h] Luzentia Solar Promotion (undated a,b).

[i] RenewableEnergyWorld.com (2008).

[j] SPG Media Limited (2007a,b).

[k] City Solar AG (undated).

[l] Project Finance Magazine (2008).

[m] RED (2008c).

[n] Nellis Air Force Base (undated); Nellis Air Force Base (2006).

[o] KYOCERA (2007).

Footnotes continued on next page.

TABLE F.3.2-2 (Cont.)

[p] Ecostream (2006).

[q] Lenardic (2008b).

[r] The Solarserver (2007).

[s] Marsden (2007); SPG Media Limited (2008a).

[t] SPG Media Limited (2008b); PowerLight (2005); The Solarserver (2008).

[u] Foro-Industrial (2008).

[v] Professor of ESO (2007); Lenardic (2008b).

[w] RED (2008a).

Source: Lenardic (2008b).

NA = not available.

areas of southern California and is likely representative of utility-scale PV facilities that will be built within the next 20 years.

Because PV technologies are not thermoelectric facilities and do not require water to support a steam cycle, operators proposing such facilities in California are not required to obtain an AFC from the CEC regardless of nameplate power rating; such facilities are instead required to obtain a conditional use permit (CUP) from the county in which they are located. On July 18, 2008, Topaz Solar Farms submitted an application for a CUP (DRC2008-00009) to San Luis Obispo County (Topaz Solar Farms, LLC 2008).[85] In April 2009, Optisolar, Inc. merged with First Solar, Inc. and the applicant switched its proposed PV technology to thin-film solar modules manufactured by First Solar. On June 25, 2009, Topaz Solar Farms, LLC submitted a revised CUP application that supersedes the July 18, 2008, application (Topaz Solar Farms, LLC 2009).[86] Changes to project parameters from the technology shift include reduced water requirements and decreased land area.

F.3.2.5 Hybrid PV Systems

Various options are available for constructing hybrid facilities involving PV technology. As was shown in Figure F.3.2-1, combining flat-plate PV systems with CPV systems is already being practiced. Likewise, the use of modules composed of different solar materials and different PV flat-plate designs in the same facility is equally feasible. However, while such options may improve overall operability or power-producing capacity, they do nothing to improve the "dispatchability" of the facility's power and thus do not significantly improve the value of the facility as a utility-scale power source. Because PV technologies do not produce steam, their hybridization with conventional thermoelectric technologies is not easily or efficiently accomplished. While it is possible to co-locate PV solar with conventional thermoelectric generation, except for the physical juxtaposition, there is really no "integration" of the two technologies. Also, because PV is not a thermal-based technology, including TES systems with PV facilities is not feasible. However, PV technologies would be suited for hybridization with energy storage in batteries for delayed delivery to the grid.[87] PV could also be adapted to generate alternative energy supplies (e.g., hydrogen through the electrolysis of water). To date, no such PV hybrids have been proposed for utility-scale PV facilities.

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[85] The entire CUP application can be viewed at http://www.slocounty.ca.gov/planning/environmental/EnvironmentalNotices/optisoloar/Optisolar_App_Submit.htm. Accessed July 14, 2009.

[86] The entire revised CUP application can be viewed at http://www.slocounty.ca.gov/planning/environmental/EnvironmentalNotices/optisoloar/topaz6-09.htm. Accessed December 1, 2009.

[87] Although batteries have been used in conjunction with small-scale distributed PV systems (DOE 2008), the technology is not considered viable for utility-scale systems at this time.

F.3.2.6 Water Demands of Utility-Scale PV Facilities

PV facilities are fundamentally different in their approach to producing electricity than CSP plants. All CSP plants produce steam to drive a conventional STG and, as a consequence, require substantial amounts of water to condense that steam so that it can be recycled. There are additional miscellaneous water demands associated with the operation of a CSP plant to support activities such as routine washing of reflectors and/or concentrators and various routine plant maintenance and cleaning activities. PV plants have similar water demands for activities such as solar panel washing and routine plant cleaning and maintenance. However, because they do not produce steam, the water demands for PV plants are substantially less than those for CSP plants of equivalent power capacity.

Although solar cells interact with the sun's photons of light energy and not its heat, they do nevertheless get hot from their exposure to the sun. Although heat can cause deterioration of a solar cell, reducing its performance and shortening its useful life, most solar cell applications are able to adequately control heat by simple convection cooling of the panels. Recent developments of concentrating devices to increase the effective area of the solar cells have introduced the potential need to install more aggressive heat rejection features. Although there is no expectation that wet closed-loop cooling systems would ever be required, any of the dry or wet/dry cooling hybrids discussed in Sections F.2.4.2.2 and F.2.4.2.3 could be adapted to CPV facilities. Less elaborate variants of those cooling technologies that could provide adequate levels of heat rejection might include forced-air cooling of individual panels or installation of completely closed cooling systems that reject heat by blowing an ambient air stream across a radiator. Such closed systems would be similar to automobile cooling systems and utilize the same glycol-based aqueous coolants. Even so, such closed systems would require only a fraction of the water required by wet closed-loop cooling systems, and the water would need only infrequent replacement to control corrosion of the cooling system's components. In areas where even this relatively small amount of water would be difficult to obtain, closed cooling systems recirculating organic-based HTFs similar to those used in ORC turbines might also be used.

F.3.3 Engineering Parameters and Resource Requirements for PV Facilities

To support an environmental impact analysis of utility-scale PV facilities, it is necessary to define representative engineering parameters and resource requirements. This section presents those data for the proposed Topaz Solar Farm facility described in Section F.3.2.4. The data presented were extracted from that facility's application for a CUP.[88] They are considered representative of similarly sized utility-scale PV facilities, although they may not anticipate parameters and requirements for future proposed facilities.

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[88] Topaz Solar Farms, LLC, submitted a revised CUP Application in June 2009. The entire revised application can be viewed at http://www.slocounty.ca.gov/planning/environmental/EnvironmentalNotices/optisoloar/topaz6-09.htm. Accessed December 1, 2009.

The critical engineering dimensions and resource needs for the Topaz Solar Farm PV facility include the following (Note: changes to project parameters associated with the revised CUP application are reflected in brackets and italics below):

- Nominal power capacity: 550 MW total (210 MW Phase 1, 340 MW Phase 2, construction initiated 4 years after Phase 1 completed)

- Project size: 6,200 acres (25.1 km^2) (5,300-acre [21.5-km^2] study area; 4,200-acre [17-km^2] ultimate project perimeter), including four *[two]* 10-acre (0.041-km^2) *[6-acre (0.024-km^2]* temporary material staging areas to support construction, all within facility boundaries

- Expected project life: 30 years

- Technology: Thin-film amorphous silicon PV *[thin-film PV modules]*

- Solar field
  - 12 PV modules/block, 5 acres (0.02 km^2)/block, 500 kW(AC)/block
  - Each PV block served by pad-mounted inverter and transformer, 20 ft × 10 ft × 8 ft high (6 m × 3 m × 2.4 m) (1,100 devices for the entire facility)
  - Each module 3.28 ft × 1.64 ft (1 m × 0.5 m), 15º tilt, maximum elevation 3 ft (0.9 m) above grade
  - Module rows separated by 5 ft (1.5 m) to prevent shading and provide access for maintenance
  - *[550 1-MW arrays, consisting of groups of modules called tables]*
  - *[45 modules per table; 6.5 acres (0.026 km^2) per table]*
  - *[10 tables per MW]*
  - *[Each table 6 ft × 60 ft (1.83 m × 18.29 m), 1.5 ft (0.46 m) high at front end, 5 ft (1.52 m) high at rear end]*
  - *[Arrays will be separated by 20-ft (6.1-m) access corridors]*

- Central electrical substation: 5acres (0.020 km^2) *[6 acres (0.024 km^2)]*, 8-ft (1.5-m) high perimeter fence

- Two-acre O&M facility (two double-wide trailers) and employee parking

- Water sources and requirements
  - Sources: on-site wells
  - Requirements, construction phase
    - Fugitive dust control: 7,200 gal/day (27.2 m^3/day), 8.0 ac-ft/yr (9.868 m^3/yr)
    - Concrete manufacturing (temporary on-site batch plant at each of four construction staging areas, 300,000 yd^3 [229,500 m^3]) total: 12,000 gal/day (45.4 m^3/day), 13.4 ac-ft/yr (16,036 m^3/yr)
    - Sanitary uses: 3,750 gal/day (14.2 m^3/day), 4.2 ac-ft/yr (5,026 m^3/yr)

- Other (initial PV panel washing): 960 gal/day (3.63 m^3/day), 1.1 ac-ft/yr (1,316 m^3/yr)
- Total, construction: 23,910 gal/day (90.5 m^3/day), 26.7 ac-ft/yr (31,951 m^3/yr) *[expected to use 20 ac-ft/yr, a maximum of 43,000 gal/day (163 m^3/day)]*

– Requirements, operations phase
  - Sanitary uses: 160 gal/day (0.61 m^3/day), 0.2 ac-ft/yr (247 m^3/yr) *[less than 100 gal/day (0.38 m^3/day)]*
  - Panel washing (once/year): 2,900 gal/day (11 m^3/day), 3.3 ac-ft/yr (4,070 m^3/yr) (requires no water for electricity generation or for cleaning modules)
  - *[35 gal/day (0.13 m^3/day) for Solar Energy Learning Center]*
  - Total, operations: 3,060 gal/day (11.58 m^3/day), 3.5 ac-ft/yr (4,317 m^3/yr) *[135 gal/day (0.51 m^3/day)]*

- Wastewater: on-site septic system, <1,500 gal/day (5.7 m^3/day) during construction, 50 gal/day (0.2 m^3/day) *[135 gal/day (0.51 m^3/day)]* during operation

- Workforce:
  – Construction: 250 *[400]* workers (daily average over a 3-year construction period)
  – Operation 10 *[15]* workers (daytime shift only, 24-h security presence)

- Transportation impacts, 3-year construction period:
  – 60 *[58]* vehicle trips/day for workforce commute
    - Shuttle buses for workers (10 *[18]* @ 20 workers each)
    - 50 *[40]* individual worker vehicles
  – Deliveries: 85 vehicle trips/day
  – Construction vehicles: 135 *[420]* will remain on-site throughout construction period, none operated on public roads

- Transportation impacts, 30-year operation period:
  – 8 *[13]* vehicles/day with 1.5 *[approximately 1]* workers/car for workforce commute
  – Deliveries, 4 *[7]* vehicles/day

F.4 TRANSMISSION LINES AND GRID INTERCONNECTIONS

F.4.1 General Information Regarding the Transmission Grid

This PEIS addresses the potential impacts of the construction and operation of transmission lines to connect solar energy facilities to the main high-voltage electric transmission grid. It is assumed that the maximum distance of transmission line construction required for any individual solar facility would be 25 mi (40 km). This section provides additional information on the major components of high-voltage transmission lines and the potential environmental impacts associated with their construction and operation. The primary factors influencing the design and performance of transmission lines are also briefly discussed. Site-specific impacts of transmission lines (e.g., impacts on specific species and habitats) are not addressed in this section.

Information presented here was taken primarily from a Technical Memorandum published by Argonne National Laboratory (Argonne 2007) and from the recently published *Final Programmatic Environmental Impact Statement, Designation of Energy Corridors on Federal Land in the 11 Western States* (DOE and DOI 2008b). Those documents, both of which are available electronically at http://corridoreis.anl.gov, provide more in-depth information on these topics.

The North American electric system includes power generation, storage, transmission, and distribution facilities in Canada, United States, and northern Mexico (Baja Norte). The high-voltage transmission grid comprises three main interconnected regions: the Eastern Interconnection, Western Interconnection, and Electric Reliability Council of Texas (ERCOT) Interconnection. The Western Interconnection serves 12 western states (including all six states within the scope of this PEIS), the Canadian provinces of Alberta and British Columbia, and Baja Norte, Mexico.

Within each interconnection, all electric utilities are interconnected and operate synchronously; that is, the generators are operated such that the peak voltage from all generators occurs simultaneously. Voltage from AC generators varies over time following a sine wave, reaching a peak or a minimum 60 times per second (60 Hz). If all the power contributions from generators were not "in phase," the voltage from one would cancel some of the voltage from others. Ensuring synchronicity is essential to the transmission grid's reliability and function. Consequently, each line segment connecting a generating facility to the transmission grid is supported by substations located either at the generator's facility or at the "point of injection" (or both) that accomplish the necessary power modifications. In addition to ensuring proper phase, transformers are present to adjust voltage to match the grid or to provide for efficient transfer of power to the point of injection. Circuit breakers are present to disconnect the facility should upset conditions occur, and at solar PV facilities inverters are present to convert the direct current produced at the solar panels to alternating current.

F.4.2 Providing for Transmission Grid Reliability and Stability

The Federal Energy Regulatory Commission (FERC) is the primary federal regulatory authority overseeing electric transmission and is responsible for ensuring the reliability of the electricity transmission grid. To further ensure system reliability, the Energy Policy Act of 2005 authorized the creation of an independent, international Electric Reliability Organization (ERO) and directed FERC to establish rules for EROs as well as a process for certification. In

July 2006, FERC approved the North American Electric Reliability Corporation (NERC) as the authorized ERO for the United States.[89]

NERC's mission is to promote reliability of the bulk electricity transmission systems (i.e., electricity transmitted at 100 kV or greater) that serve North America. To achieve that and in collaboration with all segments of the electric power industry, NERC develops and enforces FERC-approved reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. Reliability standards provide for the reliable performance of the North American bulk electric systems without causing undue restrictions or adverse impacts on competitive electricity markets.[90] To ensure consistency in the manner in which individual generating facilities are granted access to the transmission grid and to ensure that such interconnections do not jeopardize the stability of the grid, FERC has also developed a generator interconnection procedure and published a model interconnection agreement, both required to be used for generating facilities with nameplate ratings greater than 20 MW.[91]

NERC is composed of Regional Reliability Councils (RRCs), each responsible for bulk transmission within its assigned geographic area. The transmission grid segments within the six states addressed in this PEIS are under the control of the Western Electricity Coordinating Council (WECC). WECC is authorized to promulgate regional reliability standards (that must be approved by NERC and FERC)[92] to develop regional reliability criteria or planning standards that complement the NERC reliability and planning standards, or to establish consistent procedures for ensuring compliance with NERC standards among all WECC transmission system participants. Together, the NERC and WECC reliability standards dictate the design and capabilities of transmission system components, the dimensions and conditions of rights-of-way (ROWs), the configurations and capabilities of switchyards and substations, and the monitoring and operating parameters and controls of transmission line segments and interconnections.

F.4.3 Transmission Line Components

As discussed above, reliability standards, together with the characteristics and amount of power expected to be delivered, control every aspect of a solar facility's interconnection to the

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[89] More information on NERC can be found at the NERC Web site, available athttp://www.nerc.com.

[90] Currently, there are 94 FERC standards and 185 NERC standards addressing reliability of all facets of bulk electricity transmission, including design, planning, operations, infrastructure and cyber security, communication, coordination, and operational safety. All NERC reliability standards can be accessed electronically at http://www.nerc.com/files/Reliability_Standards_Complete_Set_2009Feb25.pdf.

[91] Both the interconnection procedure and agreement can be found at the FERC Web site, available at http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp). See also, FERC Order No. 2003, issued March 5, 2004, available electronically at http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/order2003-a.pdf.

[92] As of January 2009, FERC has approved eight WECC reliability standards, which can be accessed electronically at http://www.ferc.gov/industries/electric/indus-act/reliability/WEC-standards.asp.

grid, from the type and size of the electrical devices and controls required at substations, to the design, configuration, and dimensions of line components, to the width of the ROW and the manner in which it is maintained. The more critical components of interconnections are discussed below.

F.4.3.1 Tower Specifications and Construction

The towers support the conductors and provide physical and electrical isolation for energized lines. Voltage; the type, number, weight, and size of conductors (wires) to be supported (typically, three conductors for each circuit present); as well as the safe separation distances that must be maintained among energized conductors, towers, and ground obstructions to prevent faulting, combine to dictate tower specifications with respect to size, geometry, construction materials, and tower spacing. ROW circumstantial factors such as ground slope, surface and subsurface conditions, wind loading, and weather extremes such as snow and ice can impose additional requirements on the specifications of towers, their spacing, and their foundation requirements. At 500 kV, the material of construction is generally steel, although aluminum and hybrid construction, which uses both steel and aluminum, have also been used.[93] The weight of the tower varies substantially with height, duty (e.g., straight run or change in direction, river crossing), material, number of circuits, and geometry, and can range from 8,500 to 235,000 lb (3,856 to 106,594 kg). The basic function of the tower is to isolate conductors from their surroundings, including controlling the extent of their sag and slope over the expected operating temperature range. Clearances are specified for phase-to-tower, phase-to-ground, and phase-to-phase. For example, phase-to-tower clearance for 500 kV ranges from about 10 to 17 ft (3 to 5 m), with 13 ft (4 m) being the most common specification. These distances are maintained by insulator strings and must take into account possible swaying of the conductors. The typical phase-to-ground clearance is 30 to 40 ft (9 to 12 m). This clearance is maintained by setting the tower height, controlling the line temperature to limit sag, and controlling vegetation and structures in the ROW. Typical phase-to-phase separation is also 30 to 40 ft (9 to 12 m) and is controlled by tower geometry and line motion suppression.[94]

Myriad designs exist for towers, all of which can be placed into one of two general categories: lattice type or monopole. Regardless of their appearance, towers must safely support energized conductors. The voltages at which the conductors are maintained dictate the clearances that must be maintained between each conductor and other conductors, the tower, and ground

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[93] Solar facilities with capacities in the hundreds of megawatts (as is the case with the majority of existing and proposed facilities) could be served by a transmission interconnection operating at substantially less voltage (even as low as 40 kV or 69 kV), and it is likely that solar facility interconnections will operate at such lower voltages. The discussion references requirements and dimensions for a 500-kV line (the highest voltage of any existing segment within the six-state study area) as a way of demonstrating a worst-case condition that could exist for a transmission line interconnection.

[94] Other factors critical to tower and transmission line performance, such as insulator design, lightning protection, and conductor motion suppression, do not introduce additional environmental impact factors and are not discussed here.

obstructions. Those clearances dictate the physical dimensions of the towers and the necessary minimum dimensions of the operating ROW.

Tower erection involves clearing the construction area (typically as much as 80,000 ft^2 [7,432 m^2] and an adjacent tower assembly area (100 by 200 ft [30 by 61 m]) of vegetation. Creating level ground for lifting equipment is required. In general, construction ROW widths can be as much as twice the ROW width needed for safe operation. Excavation, concrete pouring, and pile driving are required to establish foundations, some of which can extend as deep as 40 ft (12 m). Each foundation may require as much as 10 yd^3 (8 m^3) of reinforced concrete. In most instances, ready-mixed concrete is delivered to the site by commercial vendors; however, at particularly remote or rugged sites, special tactics may be employed such as delivery of the concrete by helicopter or creation of a temporary concrete batch plant near the ROW. Monopole towers utilize a single reinforced-concrete foundation, formed either as a solid cylinder or in the shape of a donut. Lattice-type towers require somewhat less substantial foundations for each of their four legs.

Towers can reach to heights of 150 ft (46 m) and widths of 75 ft (23 m). To ensure adequate clearances of conductors to ground interferences, operating ROW widths could approximate twice the width of the tower. Tower spacing on level ground without special concerns for wind or ice loading on power cables would be 1,000 to 1,200 ft (305 to 366 m) for lattice towers and 800 ft (244 m) for monopole towers. Radical changes in grade (e.g., crossing a deep valley or hilly terrain) or anticipated wind and ice can greatly reduce tower spacing or require the installation of exceptionally tall towers to maintain acceptable slope of the conductors between towers or clearances of conductors to ground.

Tower erection also involves the creation of access roads with specifications (grade, turning radius, width, and weight limits) sufficient to handle large, heavy tower components, earthmoving equipment, tower erection equipment, and maintenance equipment. Laydown areas would also be created for temporary storage of tower components (typically 3 acres [0.01 km^2] in size and roughly every 10 mi [16 km] along the ROW). Tower construction can result in the loss of some vegetation, increased potential for wind- and water-induced soil erosion, impacts on surface waters from increased sediment loads, and possible impacts on groundwater from exceptionally deep foundation excavations. Most tower construction-related impacts are of short duration, however, and best management practices have been developed to minimize, if not completely mitigate, most impacts. Additional ROWs established for construction are typically returned to their natural state once construction is complete.

F.4.3.2 Conductor Specification and Installation

Transmitting electrical power over a long distance is not an efficient proposition. Even materials considered excellent conductors of electrical current offer some resistance to current flow. Resistance is typically manifested as heat.[95] Power losses as high as 10% can result.

[95] Some power is also lost due to corona discharge, the ionization of oxygen molecules in the ambient air surrounding a high-voltage conductor.

Various strategies have been pursued to eliminate or at least reduce line loss. Because electrical power (expressed in watts, kilowatts, or megawatts) is the product of voltage times current and since the amount of power lost to heat is proportional to the amount of current being transferred, transmitting electrical power at the highest possible voltage minimizes transmission losses due to heat. Alternatively, a variety of conductor compositions and constructions are currently in use to meet a variety of specific requirements. Although the ideal conductor material is one exhibiting the best electrical conductance properties, the selection of conductor materials typically represents a compromise balancing performance, cost, and weight factors. Because of its weight and cost, copper is typically replaced by aluminum, which offers greater strength-to-weight ratios than copper but only 60% of the electrical conductivity of copper. Aluminum-steel composites are also in widespread use. Most recently, ceramic fibers in a matrix of aluminum have been used, offering high strength even at the elevated temperatures that often result from high current flows during peak power demand periods.

Conductor specifications dictate tower design, specification, and spacing. Regardless of the materials selected, conductor installation is a formidable task, and conductor stringing requires substantial land areas beyond the operating ROW for the staging and operation of installation equipment. A temporary construction ROW would be required to accommodate at least two cable-pulling areas, each about 150 by 250 ft (46 by 76 m). As with tower erection areas and laydown areas, conductor-pulling areas would be returned to their native state after installation is complete.

F.4.3.3 Switchyards and Substations

To minimize power losses over long-distance transfers, existing high-voltage transmission lines in the study area are typically maintained at voltages as high as 500,000 volts (500 kV), substantially greater than the voltage at which power from a solar facility is initially produced. Consequently, the collective purpose of all the equipment in a substation is to condition the power being produced to be compatible with the power present on the grid in both voltage and phase and to provide for immediate isolation of the solar facility from the grid during upset or emergency conditions. For electrical as well as fire safety, substations are typically kept completely free of vegetation, and the area is covered in gravel to promote drainage. Individual pieces of equipment rest on concrete pads or are mounted on metal superstructures. Much of the equipment is filled with as much as hundreds of gallons of dielectric fluids[96] that provide electrical insulation as well as heat dissipation. Although spills or leaks are possible, most equipment is sealed by the manufacturer and remains sealed throughout its operating life. In addition, some designs allow the outer shell of the device to provide secondary containment of any leaked fluids. Solar facilities with nameplate ratings of hundreds of megawatts can be expected to have one or more power-conditioning areas, each comprising anywhere from 2 to 10 acres (0.01 to 0.04 km^2).

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[96] Oils containing polychlorinated biphenyls (PCBs) were once common dielectric fluids. However, modern-day equipment is free of PCBs and instead contains synthetic or mineral-based oils. Some equipment contains a gaseous dielectric material, sulfur hexafluoride.

F.4.3.4 Rights-of-Way (ROWs) and Access Roads

A ROW is a passive but critical component of a transmission line. It provides a safety margin between the high-voltage lines and surrounding structures and vegetation. The ROW also provides a path for ground-based inspections and access to transmission towers and other line components if maintenance or repairs are needed. Failure to maintain an adequate ROW can result in dangerous situations, including ground faults.

A ROW generally consists of native vegetation or plants selected for favorable growth patterns (slow growth and low mature heights). However, in some cases, access roads constitute a portion of the ROW and provide more convenient access for repair and inspection vehicles.

ROW widths are dictated primarily by the width of the towers being installed, which in most instances is directly proportional to the highest voltage of the circuits present. In some instances, ROW widths are artificially large to allow for avoidance of potentially sensitive or problematic areas along the path. Table F.4.3-1 shows the range of minimum ROW width reported by U.S. utilities for various line voltages (for one line of towers). The number of companies reporting each width provides an indication of the most common size ranges.

TABLE F.4.3-1 Minimum ROW Widths

Voltage (kV)	Range of Widths (ft)[a]	No. of Companies Reporting
<230	<50	51
	51 to 125	41
	>125	7
230	<75	40
	76 to 125	36
	>125	30
345	<75	6
	76 to 125	36
	>125	30
500	<125	4
	126 to 175	21
	>175	13

[a] For distance in meters, multiply by 0.3048.

Source: FERC (2004).

Access roads will be required; some will be temporary roads constructed only to support certain construction activities, while others will remain throughout the operating life of the transmission line and provide access to the ROW for ground-based inspections and vehicles and equipment needed for maintenance, repairs, or replacements of components. Terrain and overall length of the interconnection line segment may require multiple access roads. Road specifications are dictated by the equipment and vehicles that will use them. In most instances, access roads will enjoy separate ROWs, typically 12 to 14 ft (3.7 to 4.2 m) wide (together with a temporary construction ROW of an additional 3 ft [1 m] along either side of the road). Circumstantial factors will dictate road construction techniques, including special techniques required to cross streams, wetlands, or especially rugged terrain. Roads are likely to be finished in gravel to provide for all-weather access. Access roads that provide primary access to the ROW or to substations may have a more permanent pavement. In most instances, pre-existing roads would be sufficient for the task of transporting equipment, components, and construction vehicles to the ROW. However, in some instances modifications would be required. For example, bridges may need to be strengthened or load height clearances extended, and pathways over water courses may need to be widened and fortified.

F.4.3.5 Additional Structures

For some long-distance transmission line construction projects, additional facilities such as maintenance or repair facilities, material storage areas, administrative buildings, and operational control centers would also be constructed. However, it is not likely that any such facilities would be necessary for the grid interconnection segments being discussed here, and if they are, they would likely be the responsibility of the transmission system operator and not the solar facility operator.[97] It is more likely that at some point along its route, the transmission interconnection segment from a solar facility would share the ROW with a similar segment from another solar facility. Multiple, independent transmission lines sharing a ROW create some unique issues associated both with construction and with operation. Designs would be amended to provide adequate spacing between lines to prevent interferences or emergencies on one line from cascading to the second line. Agreements would be required among the parties involved to establish liability limits and assign responsibility for each aspect of ROW maintenance. Coordination of construction- and operation-related activities would also be addressed to prevent adverse impacts on safe operation of either line.

F.4.3.6 Hazardous Materials and Wastes

The hazardous materials used during construction of transmission lines consist primarily of fluids (lubricating oils, hydraulic fluids, glycol-based coolants, and battery electrolytes) needed to perform primary maintenance on construction vehicles and equipment. Most such materials would be present in portable containers of 55-gal (208-L) capacity or less. Some equipment cannot be easily moved (e.g., exceptionally large lifting cranes that are transported in pieces and assembled on-site, or bulldozers used for initial clearing), which may require the establishment of temporary fueling facilities consisting of portable aboveground tanks holding diesel fuel and/or gasoline.

Compressed gas cylinders of welding and cutting gases such as oxygen and acetylene and modest amounts of cleaning solvents, paints, and corrosion control coatings would also be present. Portable sanitary facilities would also be brought to the construction site. Finally, pesticides used for initial clearing of construction areas, and later in the ongoing maintenance of the ROW, may be present. At associated substations, much of the electrical equipment would be filled with dielectric fluids or gases. However, except in the case of major malfunctions that result in arcing or leaks, these dielectric materials would not be expected to require replacement, and no waste dielectrics typically result from routine operation. At the decommissioning of the

[97] The best solar resources are concentrated in relatively small geographic areas; some of these areas, however, are remote and devoid of existing high-voltage transmission line infrastructure. Nevertheless, for the purpose of this discussion, it is assumed that interconnection transmission line segments would be no more than 25 mi (40 km) in length. This assumption is supported by the existence of state initiatives, such as the Renewable Energy Transmission Initiative (RETI) in California, that seek to facilitate development of renewable energy resources in remote areas by establishing the necessary transmission infrastructure in those areas. Additional details on RETI can be found on the California Energy Commission's Web site at http://www.energy.ca.gov/reti/documents/index.html. It is further expected that similar initiatives may be pursued in other states within the study area where concentrations of renewable resources exist.

transmission line, very large electrical equipment may need to be drained before being relocated, however.

The majority of construction-related wastes are associated with vehicle and equipment maintenance. These wastes are likely to be containerized and briefly stored at the construction area before being removed to off-site treatment or disposal areas. Special arrangements may be necessary for disposition of very large quantities of vegetation resulting from ROW clearing in some locations. The expected relatively short length of transmission line interconnections suggests that, even in remote areas, there will be no need to establish employer-provided housing for the construction workforce.

Except for pesticides used in ROW maintenance, virtually no hazardous materials would be required during the operating period of the transmission line and related substations, and no operation-related wastes would be generated unless major repairs or replacements are required.

F.4.3.7 Transmission Line Operation and Maintenance

Transmission lines require very little attention and intervention during normal operation. Periodic visual inspections are conducted by driving or walking the ROW or through aircraft flyovers. Inspection frequencies are dictated largely by experience with similar lines operating in similar environments. Table F.4.3-2 shows typical inspection frequencies.

TABLE F.4.3-2 Number of Companies Reporting Various Inspection Frequencies

Frequency	Aerial	Ground
More than twice a year	25	7
Semiannual	34	22
Annual	46	76
Biennial	6	6
Every 3 years	1	6
Less than every 3 years	3	2.5
As needed	8	1
Did not report	38	7

Source: FERC (2004).

In rare instances, inspectors may need to climb the towers when close inspections are required to verify the conditions of critical components. ROW vegetation maintenance is conducted in accordance with a preapproved plan. Maintenance may include periodic tree and bush trimming or applications of pesticides, or both. As with inspections, the frequency of ROW maintenance activities is dictated by circumstances and experiences.

Substations and switchyards are also inspected regularly, typically at a higher frequency than the transmission line. Arcing in transformers may require periodic replacement of the dielectric fluids. Replacements of bushings (ceramic insulators that isolate energized wires from the metallic cases of electrical equipment or from the metal superstructures to which they are attached) may also be necessary. Depending on configuration and function, personnel may need to visit the substation or switchyard to make changes to the routing of power.

During the expected operating lifetime of a transmission line, voltage upgrades, introductions of additional circuits or "double circuits,"[98] repairs, or replacements of conductor segments or insulators may all require the reintroduction of heavy equipment of the type used for initial construction. Depending on where such activity occurs, original construction access roads and clearings that were remediated after completion of construction may need to be re-established (together with the necessary amendments to the ROW lease). The impacts of such repairs, upgrades, or refurbishments would be similar to those incurred during initial construction. Likewise, upgrades may also involve replacements of equipment at substations or switchyards.

F.4.3.8 Transmission Line Decommissioning

The expected lifetime of a transmission line is indefinite. It is more likely that the line will undergo upgrades (including replacements of conductors or towers, or both) or the introduction of additional circuits than be abandoned. However, in the event a transmission line segment is abandoned, decommissioning would involve removal of all permanent structures. On the other hand, subsurface foundations may be allowed to remain if their removal would create more disruption than their retention. Virtually all major components, towers, and conductors are likely to remain serviceable and could be reconditioned for similar application on another transmission line segment. Equipment at substations or switchyards is also likely to be appropriate for reinstallation in other parts of the transmission grid or have recycling options. Some large pieces of equipment may need to be drained of their dielectric fluids before removal and transport. Failing that, recycling options would likely exist for all major components. In most areas of the ROW, remediation involves simply allowing native vegetation to re-establish itself. Where all-weather access roads have been removed or where decommissioning activities have resulted in bare soil, fast-growing, noninvasive species may be planted to provide interim erosion control until native vegetation can be re-established.

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[98] Rather than the addition of a new, independent circuit, a double circuit may be installed. New conductors having electrical continuity with existing conductors would be installed adjacent to those conductors. This doubling of conductors allows for the transfer of the same or even greater amounts of current without causing any of the conductors to exceed their thermal limits. Double circuits are often installed when the existing circuit is at its current carrying capacity (i.e., at the thermal limits of the conductors); the circuit's capacity, however, may still be insufficient to meet forecasted peak load demands.

F.5 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained for the analyses presented in this PEIS. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed. The original information has been retained and is available through the Public Information Docket for this PEIS.

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