Appendix E: Solar Thermal – Concentrated Solar Power

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NREL Report - Concentrating Solar Power (CSP)

Central Station Solar

Concentrating Solar Power

Southern California is potentially the best location in the world for the development of large-scale solar power plants. The Mojave Desert and Imperial Valley have some of the best solar resources in the world. The correlation between electric energy demand and solar output is strong during the summer months when peak power demand occurs. This region is unique for the proximity of such an excellent solar resource to a highly populated residential and commercial region. Furthermore, the extensive AC and DC transmission network running through the region enables solar electric generation to be distributed to major load centers throughout the state. As a result of these factors and state and utility policy, the world's largest and most successful solar electric power facilities are sited in Southern California and sell power to Southern California Edison (SCE).

Concentrating Solar Power Technologies

Concentrating solar power (CSP) technologies, sometimes referred to as solar thermal electric technologies, have been developed for power generation applications. Historically, the focus has been on the development of cost-effective solar technologies for large (100 MWe or greater) central power plant applications. The U.S. Department of Energy's (DOE) Solar R&D program focuses on the development of technologies suitable for meeting the power requirements of utilities in the southwestern United States. Numerous solar technologies and variations have been proposed over the last 30 years by industry and researchers in the United States and abroad. The leading CSP candidate technologies for utility-scale applications are parabolic troughs, molten-salt power towers, parabolic dishes with Stirling engines, and concentrating photovoltaics.

Parabolic Troughs

Nine independent power producer (IPP) parabolic trough plants were built during the California renewable energy boom of the late 1980s, and they sell power to SCE. These plants have established an excellent operating track record for this technology. They have delivered power reliably to SCE during the summer on-peak time-of-use period. A number of technology advances have been made in recent years that are expected to make this technology more economically competitive in future projects. Key among these advances is the development of thermal energy storage. A number of new parabolic trough projects are currently in varying stages of project development around the world, some of these will include thermal energy storage.

Power Towers

The molten-salt power tower was developed specifically for application in utility-owned solar power stations. These are potentially the most efficient and lowest cost solar power systems. The key feature is the molten-salt working fluid, which provides efficient, low-cost thermal energy storage. This allows solar plants to be designed with high annual capacity factors or used to dispatch power to meet summer and winter peak loads. This technology has not yet been demonstrated in a commercial operating environment. As a result, significant uncertainty exists in the cost and performance of this system. A recent study by Black & Vetch[1] classified this technology as being at a pre-commercial status and thus is not yet a candidate for deployment in the commercial power market environment. A number of other power tower configurations are under development. We believe these are either less attractive or less commercially ready than the molten-salt technology.

Parabolic Dishes

Parabolic dishes with Stirling engines are considered attractive because of their modular nature (25-kWe units) and their demonstrated high solar-to-electric efficiency (~30%). Their modular nature means that plants of virtually any size could be built or expanded. These systems do not require water for cooling, which is another benefit in the desert southwest. Unfortunately, the solar application of the Stirling engine was intended to leverage automotive or other applications of this engine, and this in turn would lead to improved engine reliability and reduced cost. The other applications have not occurred to date, and they seem unlikely at present. The Black & Vetch study also found dish technology to be at a pre-commercial status and thus is also not yet a candidate for commercial deployment. Current systems have not demonstrated the level of reliability considered necessary for commercial system.

Concentrating Photovoltaics

Several vendors are currently developing concentrating photovoltaic (CPV) systems. Similar to dish/Stirling systems these systems are considered attractive because of their modular nature (25 to 50kWe units) and their potential for high solar-to-electric efficiency (>30%). These systems also do not require water for cooling. Manufactures are currently providing CPV systems, but only at a few MWe per year and they are still have limited operational experience. Costs are currently somewhere between parabolic trough and flat plate PV. It is our judgment that CPV systems could be attractive for small distributed systems (25kWe and above). It is not clear at what size the economics of a small trough plant becomes the preferred option.

NREL's Recommendation for CSP

Based on the assessment of CSP technologies above, parabolic trough technology is considered the only large-scale (greater than 50 MWe) CSP technology that is available for application in a commercially-financed power project now and in the near future (5 years). The remainder of this report thus focuses on parabolic trough technology.

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[1] Black & Veatch, 2005, "New Mexico CSP Feasibility Study, Task 7 – Development Scenarios," Presentation to New Mexico CSP Task Force, January 20, 2005.

Parabolic Trough Development and Technology Overview

The nine Solar Electric Generating Systems or SEGS, located in the California Mojave Desert are the world's largest solar power plants. These plants, developed by Luz International Limited (Luz) between 1984 and 1990, range in size from 14–80 MW and comprise 354 MW of installed electric generating capacity. More than 2,000,000 m^2 of parabolic trough collectors have been operating at the SEGS sites daily for up to 20 years and, as the year 2003 ended, these plants had accumulated 154 years of operational experience. Parabolic trough collector technology has demonstrated its ability to operate in a commercial power plant environment like no other solar technology in the world. Although Luz, the developer of these plants, filed for bankruptcy in 1991 due in large part to falling energy prices, all nine of the investor-owned plants continue to operate daily.

While no new plants have been built since 1990, significant advances in collector and plant design have been made possible by the efforts of the SEGS plants operators, the parabolic trough industry, and solar research laboratories around the world. Given the lack of construction of new megawatt-scale plants since 1990, one perception is that parabolic troughs may be a dated technology with no potential value for the future. To the contrary, the excellent operating track record of the existing plants and significant R&D advances in trough technology since the 1990s have led to a resurgence of plant development and greater promise for this technology.

This section assesses current parabolic trough solar power technology for large-scale, grid-connected power applications, ongoing R&D activity and development efforts, and economic projections for future deployment.

Development History

In 1983, Luz negotiated a power purchase agreements with SCE for the SEGS I and II plants. Later, with the advent of the California Standard Offer (SO) power purchase contracts for qualifying facilities under the Public Utility Regulatory Policy Act (PURPA), Luz was able to sign a number of SO contracts with SCE that led to the development of the SEGS III through SEGS IX projects. Initially, the plants were limited by PURPA to 30 MW in size; later this limit was raised to 80 MW. Table E.1 shows the characteristics of the nine SEGS plants built by Luz.

Table E.1 Characteristics of SEGS I through IX (Source: Luz)

SEGS Plant	1st Year of Operation	Net Output (MW_e)	Solar Field Outlet Temp. (ºC/°F)	Solar Field Area (m^2)	Solar Turbine Eff. (%)	Fossil Turbine Eff. (%)	Forecast Annual Output (MWh)
I	1985	13.8	307/585	82,960	31.5	-	30,100
II	1986	30	316/601	190,338	29.4	37.3	80,500
III & IV	1987	30	349/660	230,300	30.6	37.4	92,780

V	1988	30	349/660	250,500	30.6	37.4	91,820
VI	1989	30	390/734	188,000	37.5	39.5	90,850
VII	1989	30	390/734	194,280	37.5	39.5	92,646
VIII	1990	80	390/734	464,340	37.6	37.6	252,750
IX	1991	80	390/734	483,960	37.6	37.6	256,125

In 1991, Luz filed for bankruptcy when it was unable to secure construction financing for its tenth plant (SEGS X). Though many factors contributed to the demise of Luz, one fundamental problem was that the cost of the technology was too high to compete in the changing power market. Lotker[2] describes the events that enabled Luz to successfully compete in the power market between 1984 and 1990, and many of the institutional barriers that contributed to their eventual downfall. However, the ownership of the SEGS plants was not affected by the status of Luz because the plants had been developed as independent power projects owned by investor groups, and all nine plants continue in daily operation today. However, changes in the ownership structure has occurred at several of the plants.

Figure E.1 shows the five 30-MW SEGS plants at Kramer Junction, California. The large fields with rows of parabolic trough collectors are readily apparent. The five 30-MW power plants can be observed near the center of each solar field.

[2] Lotker, M., (1991): Barriers to Commercialization of Large-Scale Solar Electricity: Lessons Learned from the Luz Experience, Report No. SAND91-7014, Sandia National Laboratories, Albuquerque, NM.

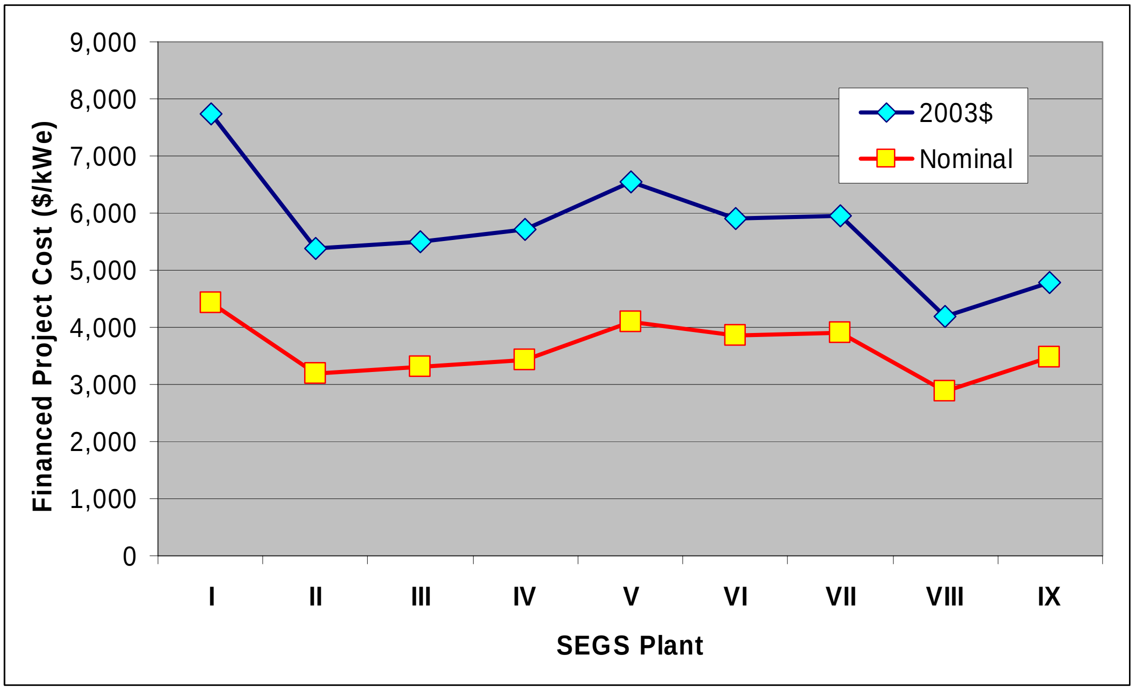
Figure E.1: SEGS III–SEGS VII Solar Plants at Kramer Junction, California

Cost of the SEGS Plants

Detailed cost data are not available for the SEGS plants. This is partially because Luz did not actually track expenses against individual projects. However, information on the financed sales price of the SEGS plants is available[3]. The financed project cost (FPC) of each SEGS plant is shown in Figure E.2. It is important to note that these costs include not only the capital cost but also project development and financing costs, interest during construction, and debt reserve costs. For example, data from SEGS IX indicate that these other noncapital costs were 11% of the financed price. The FPC is shown in nominal dollars per kilowatt, which is the cost of the project the year it was built. The costs have been normalized to 2003 dollars using the Consumer Price Index. This shows what the cost per kilowatt for these plants would be in 2003 dollars. For example, SEGS I cost $4400/kWe in 1984, which corresponds to $7738/kWe in 2003 dollars.

[3] Luz International Limited, (Jan. 1990): "SEGS IX Proposal for Project Debt".

Figure E.2: Financed Project Cost Data for SEGS Plants



Trough Development after Luz

Since the demise of Luz, a number of events and R&D efforts have helped to resurrect interest in parabolic trough technology. In 1992, Solel Solar Systems Ltd. purchased Luz manufacturing assets in Israel, providing a source for the Luz collector technology and key collector components. In the same year, a 5-year R&D program, designed to explore opportunities to reduce operations and maintenance (O&M) costs, was initiated between the operator of the SEGS III through SEGS VII plants (KJC Operating Company) and Sandia National Laboratories (SNL)[4]. This program resulted in a number of incremental advances in the technology that helped to significantly reduce O&M costs at existing plants and increase annual power generation. In 1996, the Direct Solar Steam (DISS) project was initiated at the Plataforma Solar de Almería (PSA), a solar test facility in Spain, to test parabolic trough collectors that generate steam directly in the solar field[5].

In 1998, an international workshop on parabolic trough technology led to the development of a parabolic trough technology roadmap[6]. The roadmap identified the technology development necessary to reduce the cost or improve the reliability and performance of parabolic trough technology. The U.S. DOE and others have subsequently used this roadmap to help guide

[4] Cohen, G.; Kearney, D.; and Kolb, G., (1999): Final Report on the Operation and Maintenance Improvement Program for CSP Plants, Report No. SAND99-1290, Sandia National Laboratories, Albuquerque, NM.

[5] Zarza, E.L.; Valenzuela, J.L.; Weyers, H.D.; Eickhoff, M.; Eck, M.; and Hennecke, K. (2001): "The DISS Project: Direct Steam Generation I Parabolic Trough Systems—Operation and Maintenance Experience—Update on Project Status," Journal of Solar Energy Engineering (JSEE), submitted.

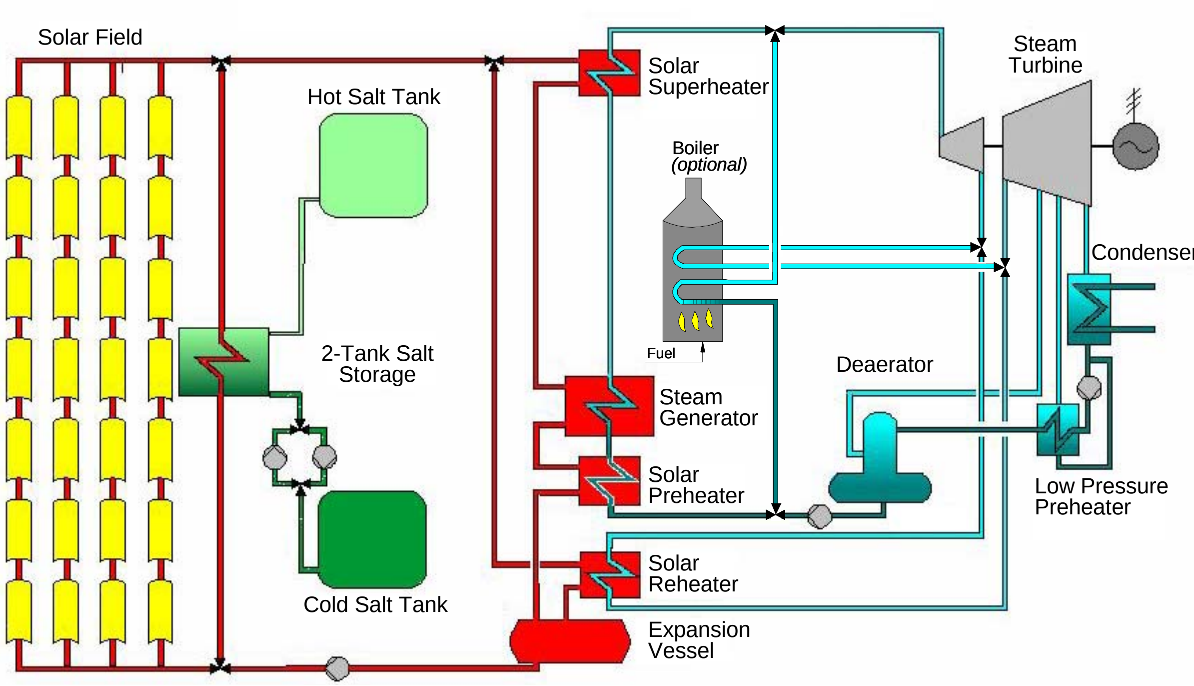
[6] Price, H.; and Kearney, D. (1999): Parabolic-Trough Technology Roadmap: A Pathway for Sustained Commercial Development and Deployment of Parabolic-Tough Technology, NREL/TP-550-24748, NREL Golden, CO.

renewed R&D investments in the technology. New technologies are currently being developed to enhance capabilities and reduce the cost of the next-generation trough plants. Developments focus on improved trough concentrator design, advances to the trough receiver, improved reflectors, development of thermal storage, and advances in power cycle integration.

Technology

Parabolic Trough Power Plant Technology
The current state-of-the-art in parabolic trough plant design is an outgrowth of the Luz SEGS power-plant technology. Parabolic trough power plants consist of large fields of parabolic trough collectors, a heat-transfer fluid/steam generation system, a Rankine steam turbine/generator cycle, and thermal storage or fossil-fired backup systems (or both). These systems are illustrated schematically in Figure E.3.

Figure E.3: Schematic Flow Diagram of Parabolic Trough Plant



The technology can be described as follows. The solar field is modular in nature, and it comprises many parallel rows of solar collectors aligned on a north-south horizontal axis. The linear parabolic-shaped reflector in each solar collector focuses the sun's direct beam radiation on the linear receiver at the focus of the parabola as seen in Figure E.4.

The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the linear receiver. A heat transfer fluid is heated to 391ºC as it circulates through the receiver and returns to a series of heat exchangers in the power block, where the fluid is used to generate high-pressure superheated steam (100 bar, 371ºC). The superheated steam is then fed to a conventional reheat steam turbine/generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps to be transformed back into steam. Condenser cooling is provided by mechanical draft wet cooling towers. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field.

Figure E.4: Parabolic Trough Collector (Source: PSA)

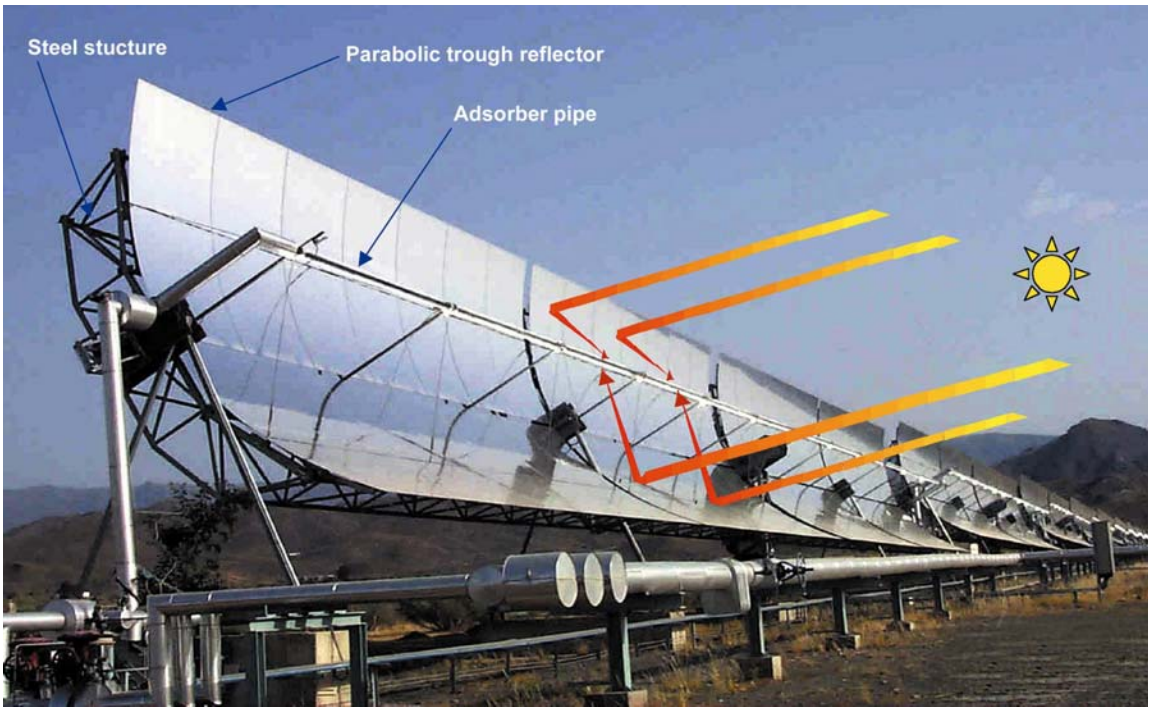


Figure E.5 is a view of the 30-MWe SEGS III solar field of parabolic trough solar collectors at Kramer Junction, California. The figure shows the large field with rows of parabolic trough collectors.

Figure E.5: SEGS III Solar Plants at Kramer Junction, California

Parabolic Trough Collector Technology

The solar field's basic component is the solar collector assembly (SCA). Each SCA is an independently tracking group of parabolic trough solar collectors made up of parabolic reflectors (mirrors); the metal support structure; the receiver tubes; and the tracking system that includes the drive, sensors, and controls. The solar field in a parabolic trough power plant is made up of hundreds, and potentially thousands, of SCAs.

Table E.2: Luz Solar Collector Assembly (SCA) Characteristics

Collector	Luz LS-1	Luz LS-2	Luz LS-3	EuroTrough ET-100/150	Solargenix DS-1
Year	**1984**	**1988**	**1989**	**2004**	**2004**
Area (m^2)	128	235	545	545/817	470
Aperture (m)	2.5	5	5.7	5.7	5
Length (m)	50	48	99	100/150	100
Receiver Diameter (m)	0.042	0.07	0.07	0.07	0.07
Concentration Ratio	61:1	71:1	82:1	82:1	71:1
Optical Efficiency	0.734[a]	0.764[a]	0.8[a]	0.78[b]	0.78[b]
Receiver Absorptivity	0.94	0.96	0.96	0.95	0.95

Mirror Reflectivity	0.94	0.94	0.94	0.94	0.94
Receiver Emittance	0.3	0.19	0.19	0.14	0.14
@ Temperature (ºC/ºF)	300/572	350/662	350/662	400/752	400/752
Operating Temp. (ºC/ºF)	307/585	391/735	391/735	391/735	391/735

Notes: (a) Luz specification, (b) Based on field measurements

Table E.2 shows the design characteristics of the three generations of Luz SCAs and two new designs currently under development. The general trend has been to build larger collectors with higher concentration ratios (collector aperture divided by receiver diameter) to maintain the collector thermal efficiency at higher fluid outlet temperatures.

The LS-3 collector was the last design produced by Luz. It was used primarily at the larger 80-MW plants. The LS-3 collector and its components can be described as follows. The LS-3 reflectors are made from hot-formed, mirrored glass panels, supported by the truss system that gives the SCA its structural integrity. The aperture or width of the parabolic reflectors is 5.76 m, and the overall SCA length is 95.2 m (net glass). The mirrors are made from a low-iron float glass with a transmissivity of 98%. The mirrors are silvered on the back and then covered with several protective coatings. The mirrors are heated on accurate parabolic molds in special ovens to obtain the parabolic shape. Ceramic pads used for mounting the mirrors to the collector structure are attached with a special adhesive. These high-quality mirrors allow 98% of the reflected rays to be incident on the linear receiver.

The parabolic trough linear receiver, also referred to as a heat collection element (HCE), is one of the primary reasons for the high efficiency of the Luz parabolic trough collector design. The HCE consists of a 70-mm steel tube with a cermet selective surface, surrounded by an evacuated glass tube. The HCE incorporates glass-to-metal seals and metal bellows to achieve the vacuum-tight enclosure. The vacuum enclosure serves primarily to protect the selective surface and to reduce heat losses at high operating temperatures. The vacuum in the HCE is maintained at about 0.0001 mm Hg (0.013 Pa). The cermet coating is sputtered onto the steel tube to give it excellent selective heat transfer properties, with an absorptivity of 0.96 for direct beam solar radiation, and a design emissivity of 0.19 at 350ºC (662°F). The outer glass cylinder has an antireflective coating on both surfaces to reduce reflective losses off the glass tube. Getters, metallic substances that are designed to absorb gas molecules, are installed in the vacuum space to absorb hydrogen and other gases that permeate into the vacuum annulus over time.

The SCAs rotate around the horizontal north/south axis to track the sun as it moves through the sky during the day. The axis of rotation is at the collector center of mass to minimize the tracking power required. The drive system uses hydraulic rams to position the collector. A closed-loop tracking system relies on a sun sensor for the precise alignment required to focus the sun on the HCE during operation to within +/- 0.1 degree. The tracking is controlled by a local controller on each SCA. The local controller also monitors the HTF temperature and reports operational status, alarms, and diagnostics to the main solar field control computer in the control room. The SCA is designed for normal operation in winds up to 25 mph (40 km/h) and somewhat reduced accuracy in winds up to 35 mph (56 km/h). The SCAs are designed to withstand a maximum of 70 mph (113 km/h) winds in their stowed position (in which the collector is aimed 30º below the eastern horizon).

Operating Experience of the SEGS Plants

The SEGS plants offer a unique opportunity to examine the operational track record of large parabolic trough plants, Even though the 9 plants in the Mojave Desert of California with a cumulative capacity of 354 MWe were the first such plants built, they all remain operational (in 2004) and provide an excellent resource for performance and O&M data.

Operations and Maintenance (O&M) of Solar Power Plants

Parabolic trough solar power plants operate similar to other large Rankine steam power plants except that they harvest their thermal energy from a large array of solar collectors. The existing plants operate when the sun shines and shut down or run on fossil backup when the sun is not available. As a result the plants start-up and shutdown on a daily or even more frequent basis. Compared to a base load plant, this introduces additional difficult service requirements for both equipment and O&M crews. The solar field is operated whenever sufficient direct normal solar radiation is available to collect net positive power. This varies due to weather, time of day, and seasonal effects due to the cosine angle effect on solar collector performance; generally, the lower limit for direct normal radiation in the plane of the collector is about 300 W/m^2. Since none of the plants currently have thermal storage[7], the power plant must be available and ready to operate when sufficient solar radiation exists. The operators have become very adept at keeping the plant on-line at minimum load through cloud transients to minimize turbine starts, and at starting up the power plant efficiently from cold, warm or hot turbine status.

The O&M of a solar power plant is very similar to other steam power plants that cycle on a daily basis. The plants are staffed with operators 24 hours per day, using a minimal crew at night; and require typical staffing to maintain the power plant and the solar field. Although solar field maintenance requirements are unique in some respects, they utilize many of the same labor crafts as are typically present in conventional steam power plants (e.g., electricians, mechanics, welders). In addition, because the plants are off-line for a portion of each day, operations personnel can help support scheduled and preventive maintenance activities. A unique but straightforward aspect of maintaining solar power plants is the need for periodic cleaning of the solar field mirrors, at a frequency dictated by a tradeoff between performance gain and maintenance cost.

Early SEGS plants suffered from a large number of solar field component failures, power plant equipment not optimized for daily cyclic operation, and operation and maintenance crews inadequately trained for the unique O&M requirements of large solar power plants. Although the later plants and operating experience has resolved many of these issues, the O&M costs at the SEGS plants have been generally higher than Luz expectations. At the Kramer Junction site[8], the KJC Operating Company's O&M cost reduction study addressed many of the problems that were causing high O&M costs.

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[7] The SEGS I plant initially had 3-hours of thermal energy storage, but the system was damaged in a fire in 1999.
[8] The SEGS plants are located at three different sites, with separate O&M companies: 44 MWe at Daggett, Calif., 150 MWe at Kramer Junction, and 160 MWe at Harper Lake.

Key accomplishments included:

- Solving HTF pump seal failures resulting from daily thermal and operational cycling of the HTF pumps,
- Reducing HCE failures through improved operational practices and installation procedures,
- Improved mirror wash methods and equipment designed to minimize labor and water requirements and the development of improved reflectivity monitoring tools and procedures that allowed performance based optimization of mirror wash crews, and
- Development of a replacement for flex hoses that uses hard piping and ball joints; resulting in lower replacement costs, improved reliability, and lower pumping parasitics.

Another significant focus of the study was the development of improved O&M practices and information systems for better optimization of O&M crews. In this area, important steps were:

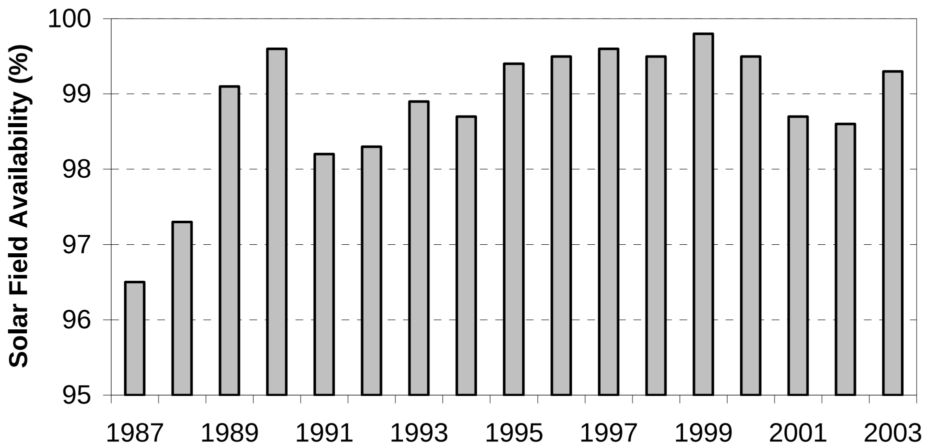
- An update of the solar field supervisory control computer located in the control room that controls the collectors in the solar field to improve the functionality of the system for use by operations and maintenance crews,
- The implementation of off-the-shelf power plant computerized maintenance management software to track corrective, preventive, and predictive maintenance for the conventional power plant systems,
- The development of special solar field maintenance management software to handle the unique corrective, preventive, and predictive maintenance requirements of large fields of solar collectors,
- The development of special custom operator reporting software to allow improved tracking and reporting of plant operations and help optimize daily solar and fossil operation of the plants, and
- The development of detailed O&M procedures and training programs for unique solar field equipment and solar operations.

As a result of the KJC Operating Company O&M cost reduction study and other progress made at the SEGS plants, solar plant O&M practices have evolved steadily over the last decade. Cost effectiveness has been improved through better maintenance procedures and approaches, and costs have been reduced at the same time that performance has improved. O&M costs at the SEGS III-VII plants have reduced to about 25 USD/MWh. With larger plants and utilizing many of the lessons learned at the existing plants, expectations are that O&M costs can be reduced to below 10 USD/MWh at future plants.

Solar Plant Availability

Solar plants differ from conventional fossil and nuclear power plants in that they must harvest their fuel via the solar field. Thus the availability of the solar field becomes a key indicator of potential plant performance. Figure E.6 shows the average solar field availability for the five 30-MW SEGS plants at Kramer Junction from 1987 to 2003. Solar field availability refers to the percentage of the solar field that is available at any time to track the sun. The year 1987 was the first year of operation for the first two plants at Kramer Junction. The data displays a steady trend of improved solar field availability through the life of the plants. The drop in availability in 1991 and 1992 was caused primarily by the bankruptcy of Luz in the summer of 1991, which resulted in a change in plant ownerships and management of the O&M company that effectively eliminated the supply of several key solar field spare parts. Now the availability is controlled by management decisions on the most cost-effective replacement strategy.

Figure E.6: Average Solar Field Availability for the Five SEGS Plants Located at Kramer Junction, CA (Source: KJC Operating Company)



The SEGS power plants are conventional Rankine cycle steam power plants. For the most part, these plants have maintained good overall equipment availability. Although daily cycling of the plant results in a more severe service situation than base or intermittent load operation, daily nighttime outages allow some maintenance activities to be conducted while the plant is off-line, helping to maintain high availability during daytime solar hours. During normal day-to-day operation, it takes approximately 45 to 90 minutes to start up the plant, from initial tracking of the solar field to synchronization of the turbine generator. During the summer, the plant can be on-line in approximately 45 minutes. It takes up to twice as long in the winter because of the lower solar input to the plant. Once the plant is on line, the turbine can be ramped up to full load in a matter of minutes. Because of their design warm-up characteristics, the natural-gas-fired boilers take longer to bring on line than the solar field and solar heat exchangers. The natural-gas-fired boilers must be warmed up more slowly to minimize thermal stresses on the boiler drum.

Since the total daily plant output varies significantly between the summer and winter seasons, the parabolic trough plants track the impact on availability as a function of lost solar generation. A full day outage in the winter may result in losing only 20% as much solar generation as would be lost by a full day outage in the middle of the summer. Thus, the plants schedule their annual maintenance outages during the November to February time frame when solar output is lowest. KJC Operating Company, the operator of the five 30-MWe trough plants at Kramer Junction, has maintained detailed scheduled and forced outage data[9]. These plants typically schedule an 8-day outage each year and an extended outage (5-8 weeks) about every 10 years. They track availability as a function of the impact on solar generation. Table E.3 shows forced and scheduled outages over a five-year period for these

[9] KJC Operating Company, "SEGS Acquaintance & Data Package", Boron, CA, September 2002.

five plants as a function of lost solar generation. The high forced outage rate during 2000 was due to problems with tube leaks on the solar steam generators. These problems were resolved and the forced outage rate was reduced again in 2001. The period shown below includes both routine annual and 10-year extended outages; specifically each year includes an 8-day outage at four of the plants and a 5-8 week outage at the fifth plant. High-wind outages occur when wind speeds exceed 35 mph and the solar field must be stowed to protect it from damage. Over this period the plants experienced a solar-output-weighted scheduled and forced outage rate of 4.4%. Without inclusion of the extended outages, the outage rate drops below 4%. This level of power plant availability is considered excellent for any power plant. The SEGS plants have a projected life of 30 years. The solar field and conventional steam cycle power equipment shows every sign of meeting and exceeding that lifetime.

Table E.3: Forced and Scheduled Outages for SEGS III-VII as a Function of Lost Solar Generation

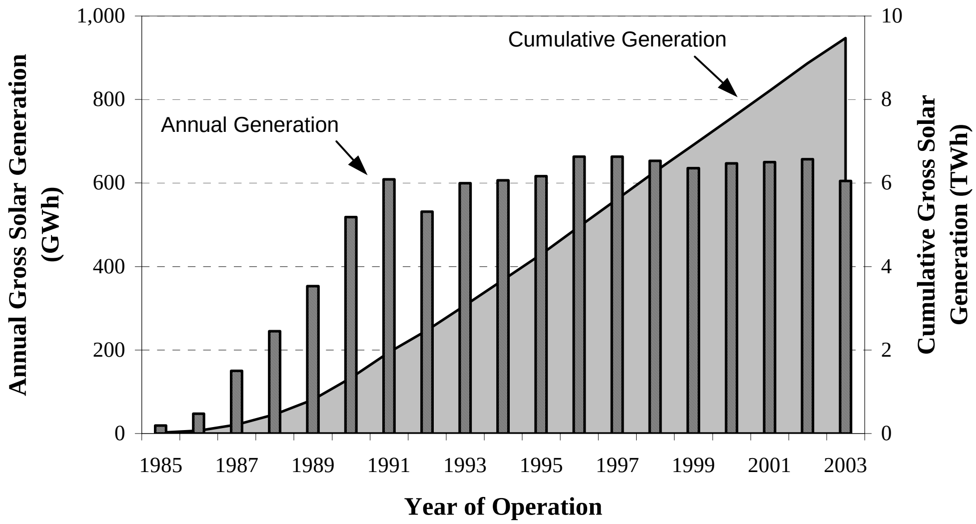
	1997	1998	1999	2000	2001
Forced Outages	0.5%	1.0%	0.8%	3.7%	0.9%
Scheduled Maintenance	1.6	0.9	1.5	1.2	2.2
High Wind Outage	1.2	1.8	1.7	2.2	0.7
Force Majeure	0.0	0.1	0.0	0.0	0.0
Total	**3.3%**	**3.8%**	**4.0%**	**7.1%**	**3.8%**

Solar Electric Generation

The best performance indicator of the SEGS plants is the gross solar-to-electric performance. Figure E.7 shows the annual and cumulative gross solar electric generation for the nine SEGS plants through the end of 2003[10]. The increasing annual generation during the first 7 years shows the impact of new plants coming online. The dip in annual generation during 1992 was due to the Mount Pinatubo Volcano in the Philippines. The volcano erupted during the summer of 1991 and resulted in a noticeable reduction in direct normal solar radiation during 1992. Of significance is the sustained level of performance over the last 11 years. Cumulative solar generation from these plants should exceed 10 terawatt hours during 2004.

[10] Frier, S., 2003, "SEGS Overview," Presentation to Global Market Initiative, Palm Springs, California, October 22, 2003.

Figure E.7: Annual Gross Solar Generation for SEGS I-IX [7]

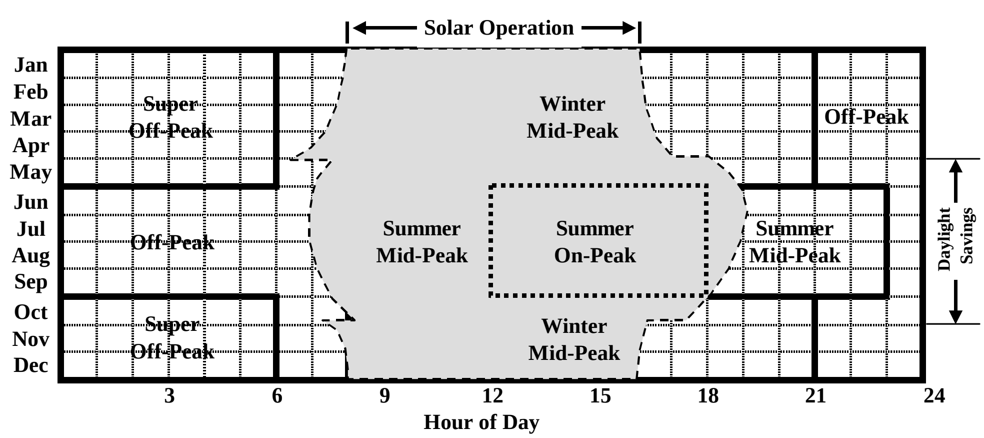


On-Peak Electric Generation

The SEGS plants sell power to the local utility, Southern California Edison (SCE). As part of their contract with SCE, the SEGS plants are required to generate power at a specified level during the utility's peak electric demand period.

Figure E.8 is a graphical representation of the different SCE time-of-use (TOU) periods during the year. The summer on-peak period has the highest demand for power. The shaded region in the figure shows the time during the day when parabolic trough plants normally operate. In general, parabolic trough plants are well suited for generating power during the SCE summer on-peak TOU period.

Figure E.8: Power Utility Time-of-Use and Solar Operation



To help ensure that the SEGS plants can operate at full rated output during the summer on-peak period, the SEGS plants have the capability to use a backup fossil energy for periods when solar energy is not available.

Figure E.9 shows gross electric output for three days in 1999 from one of the 30-MW SEGS plants at Kramer Junction. Day 172 is the summer solstice (June 21), which is the longest solar day of the year. On day 172, the plant operated from solar input only and the plant was able to operate during the summer on-peak period from 12 noon to 6 pm averaging above rated capacity for the period (30 MW net or approximately 33 MW gross). Days 260 and 262 represent 2 days near the fall equinox in September. Day 262 was a weekend day, so the plant operated on solar input only. The figure shows that the plant was not able to maintain full rated output on solar energy alone during the 12 noon to 6 pm time frame. Day 260 is a weekday with solar output in the morning similar to that of day 262, but the backup natural gas fired boiler was used in the afternoon to supplement the solar input to allow the plant to operate at rated capacity during the afternoon on-peak period from noon to 6 pm. This figure clearly illustrates how the hybrid SEGS plants have been able to operate and provide power to the utility when it is needed most.

Figure E.9: Electric Output from 30-MW SEGS plant (Source: KJC)

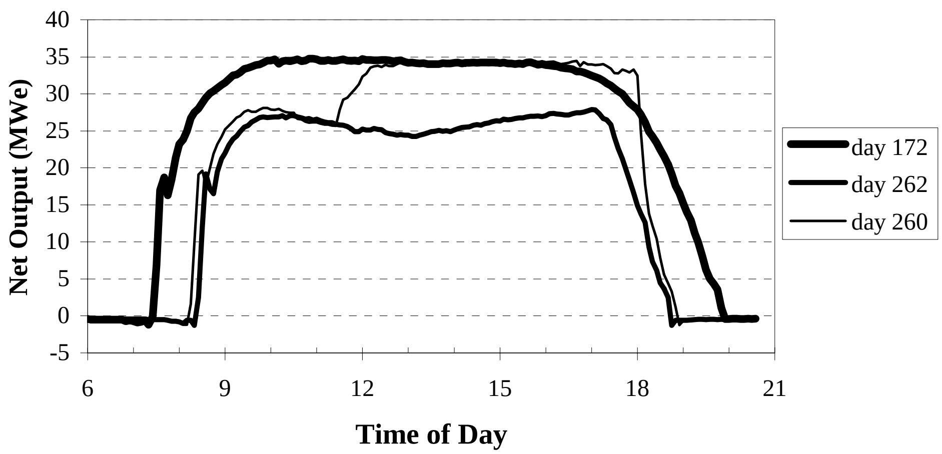
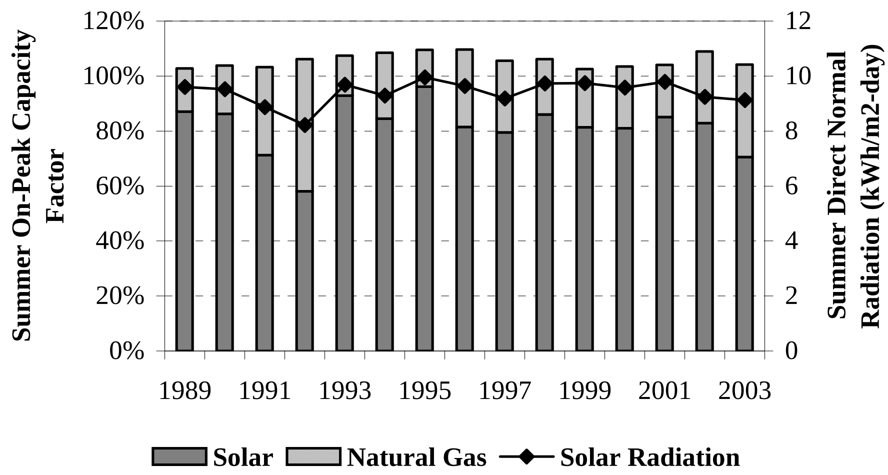


Figure E.10 shows the on-peak capacity factor for the five 30-MWe parabolic trough plants at Kramer Junction over the last 15 years. With the aid of the fossil backup, the plants have exceeded 100% of rated net capacity for every one of the last 15 years. The plants have averaged about 80% of rated capacity from solar energy alone with natural gas used to fill in to 100% capacity. Note that solar output was low in 1991 and 1992 as a result of the eruption of the Mount Pinatubo volcano.

Figure E.10: SEGS III-VII On-Peak Capacity for the Last 15 Years



Trough Power Plant Performance Characteristics

Solar thermal electric power plants are designed to harvest available sunlight, either converting it to electricity immediately, or storing it for future use. The ability to store collected thermal energy is particularly important and can lead to a solar-only power plant with firm dispatching capability. Significant flexibility exists to design plants to provide specific energy services, that is, MWe capacity, ability to meet peak loads, and tailored annual energy production. Design tools have been developed that determine the proper collector field capacity, energy storage capacity, and turbine size to produce the required energy, given expected solar insolation and climatic conditions at each site. The evaluation is dominated by the variability of the solar resource. Some of the relevant data are totally predictable (such as when the sun will rise on a given day), but most of the information depends on historically valid weather data.

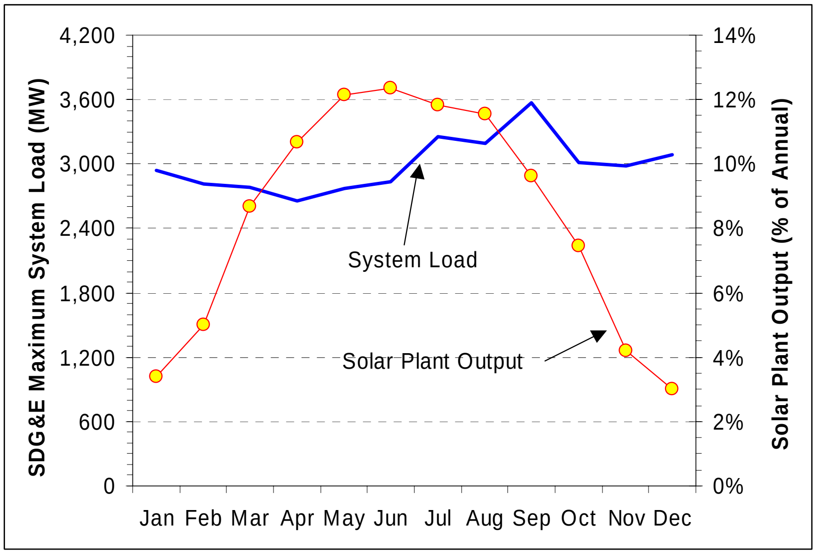
Correlation with SDG&E System Loads

SDG&E Seasonal Load Profile

Figure E.11 shows the peak SDG&E peak system load by month for 2002. The peak system load occurs in late summer/early fall, and the minimum occurs in the spring. The figure also shows the relative monthly solar output from a parabolic trough plant. There is not a strong seasonal correlation between the output of the solar plant and the peak system demand. Solar output peaks during June, and the SDG&E system load peaks in September.

Figure E.11 also reveals the substantial change in monthly output from winter to summer at a parabolic trough plant.

Figure E.11: Comparison of 2002 SDG&E Peak System Load and Monthly Output from Solar Plant



Daily Load Profile

Figure E.12 shows the average SDG&E hourly system load for three months during 2002. The figure includes data for the months of December, May, and September. September shows the highest peak loads because of high afternoon air-conditioning use. January shows an evening peak because of evening lighting and electric heating loads. May is one of the lowest demand months because of the lack of high heating or cooling loads. The peak demand for power is about 30% higher in September than in April. All months clearly show increased demand for power during the day and into the evening. Solar plants are well suited to meet the daytime peak. With thermal storage, they are able to meet evening peak loads, as well.

Figure E.12: SDG&E Monthly Average System Load for 2002

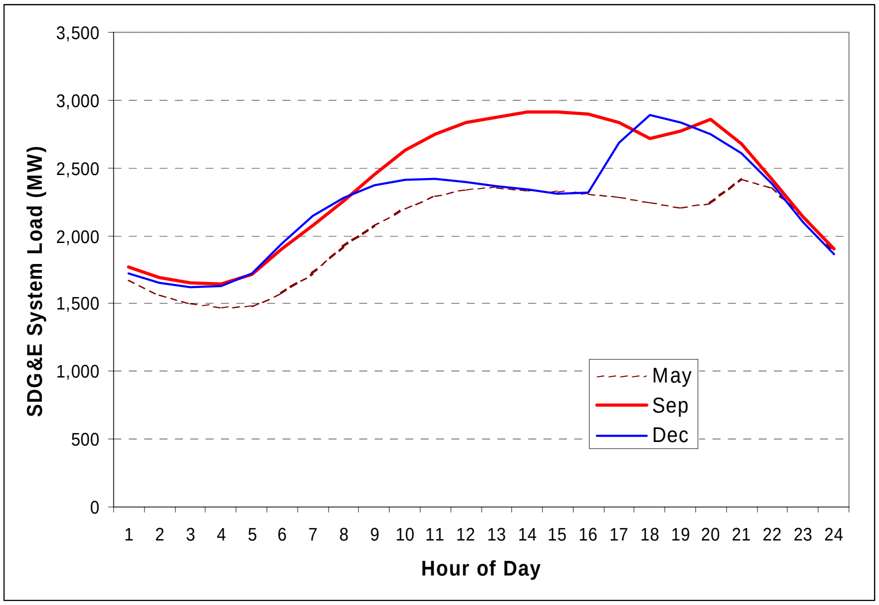
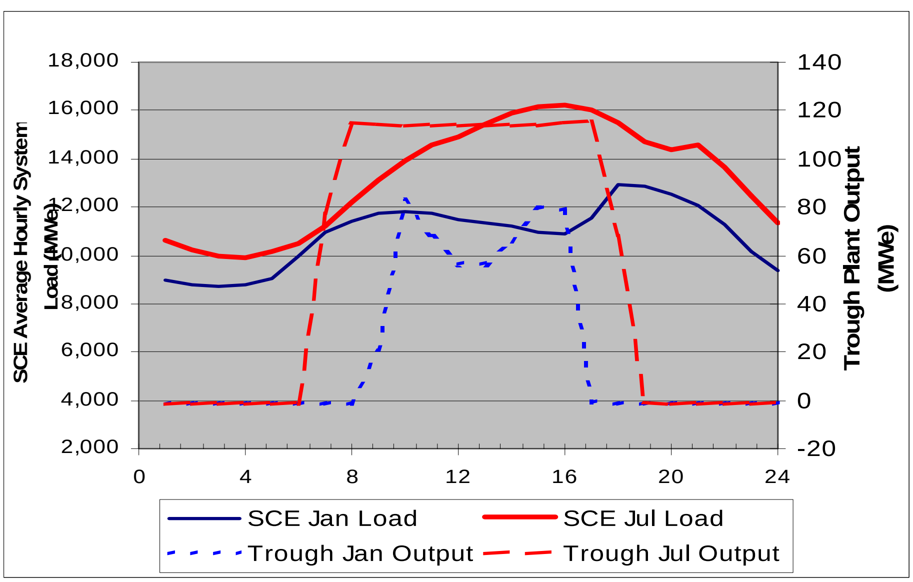


Figure E.13 shows an overlay of modeled hourly solar output for a 100-MWe parabolic trough plant and the SCE system load (similar to the SDG&E load) for January and July using solar resource data from Kramer Junction. During the summer, the solar output will help reduce the peak load. But in January, the solar output does not help reduce the peak load and may in fact aggravate the dip between the morning and evening peaks. The addition of thermal storage or hybridization can help resolve this effect. Both thermal storage and hybridization provide opportunities for firm power from large-scale solar power plants.

Figure E.13: Overlays of SCE System Load and 100-MWe Trough Plant

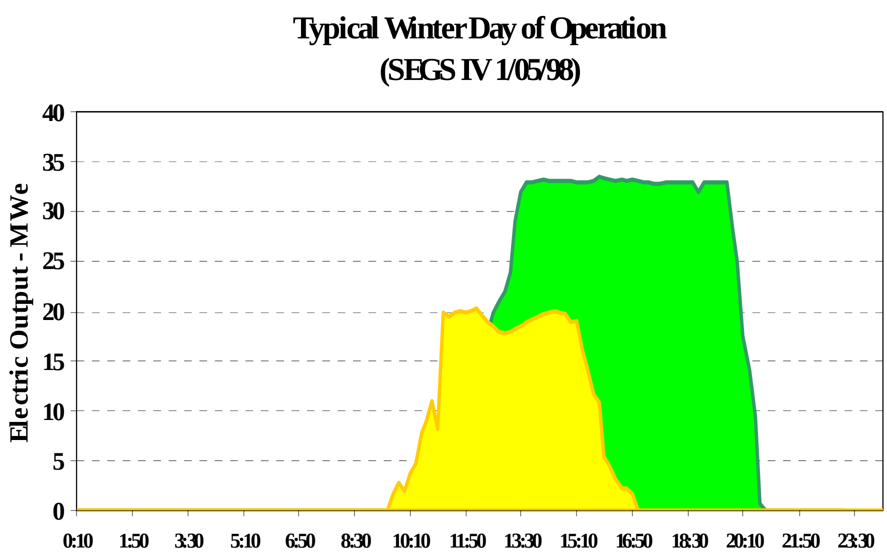


Hybridization
Hybridization means that the solar plant can also be operated by using some backup fuel, typically natural gas. All existing trough plants are hybrid plants. They either have a backup natural-gas-fired boiler that can generate steam to run the turbine, or they have an auxiliary natural-gas-fired heater for the solar field fluid that can be used to produce electricity. Sensible, cost-effective operation of a hybridized solar plant dictates that natural gas will be used periodically only to supplement electrical production. The fossil energy would likely be used only for economic dispatch during on-peak or mid-peak periods. The system heat rate is high, since the natural gas is being used in a conventional steam power plant instead of a combined cycle. Also, current plants are limited by their Federal Energy Regulatory Commission (FERC) "qualifying facility" status, which caps natural gas use to 25% of energy input to the plant.

Figure E.9 shows an example of how hybridization is used to support summer on-peak generation.

Figure E.14 shows an example of a hybrid parabolic trough plant operating on solar energy during a day in January and using fossil backup to generate power during the evening.

Figure E.14: Solar and Fossil Output from Hybrid Parabolic Tough Plant



Thermal Energy Storage
Thermal energy storage (TES) allows solar energy to be collected when the sun is out, and then to be stored for use in the power plant at another time. TES can be used to dispatch solar power when it makes the most economic sense. Solar energy can be collected during the day and power dispatched to the grid at night. The SEGS I plant operated in this manner for 13 years to meet a winter on-peak TOU period (5-9 pm). TES can also be used to increase the annual capacity factor of the plant. A solar plant without TES is limited to an annual capacity

factor of 20% to 30%. By adding thermal storage, we can oversize the solar field so that more energy is collected during the day than can be used by the steam turbine. The excess energy is then stored for use at night. If desired and if warranted by projected revenues, solar plants with TES can be designed to achieve annual capacity factors greater than 60% for parabolic troughs, and greater than 70% for power towers.

Resource Intermittency
Solar power is often considered to be an intermittent power resource similar to wind power. While this characterization is true to a point, the solar resource is much more predictable and reliable than a typical wind resource. That is, we know when the sun will rise and set, though of course we don't always know whether it will be cloudy or hazy. In excellent solar locations like the Mojave Desert where the SEGS plants are located, cloudy weather only reduces solar output significantly (>50%) on 14% of the days of the year (based on an analysis of a 30-year National Solar Radiation Data Base (NSRDB) data set from Barstow, California). In addition, reasonably good forecasts of the solar resource and resulting power generation can be made 24 hours in advance. When the solar resource forecast is uncertain (for example, when a storm front is moving through), this is usually known as well. The operators at the SEGS facilities have become good solar resource forecasters. They often schedule maintenance outages for times when extended days of cloudy weather are expected.

Solar Supply Consortium
This section discusses current solar supply consortia and suppliers of key parabolic trough solar components.

Developers

At present, several companies are prepared to offer trough solar steam systems for U.S. domestic and international projects. The companies on the list below are either actively involved in large-scale plant development or are tied to major component suppliers of trough technology. All have ties through equipment and expertise to the SEGS plants, to varying degrees. SolarGenix and Solar Millennium are developing advanced collector designs, partially with development funding from the U.S. Department of Energy and the European Union, respectively. Solel was formed after the demise of Luz, and the company obtained manufacturing facilities and technology data and documentation that had been part of Luz Industries Israel. SolarGenix, Solar Millenium, and Solel all have responded to GEF bids for international projects. Key factors in providing credible bids on projects include having technology rights to solar field design and being able to provide adequate warranties for solar system performance. FPL Energy recently purchased SEGS III-VII at Kramer Junction. FPL Energy is also interested in becoming a developer of trough plants.

Key Solar Component Suppliers

The reflective panels, or mirrors, and receivers are the unique components of a trough solar system. The German company Flabeg supplied the original mirrors to all the SEGS plants at the time of construction, has continued to supply spare parts to the plants as requested, and is ready to supply mirrors to new plants. The quality of the mirrors is excellent, and there have been some advances in the design of the mirror attachments and coatings during the last decade.

The receivers, termed *heat collection elements*, or HCE's, by Luz, are the most unique component. Solel acquired the HCE manufacturing facilities from Luz and has continued to supply that component for spare parts. Important advances have been achieved in performance, as discussed elsewhere in this report. Recently, the experienced and respected German company Schott Glass has announced active development of a new receiver for trough technology, similar to the Luz/Solel design but with important advanced features. Schott has begun prototype testing at the Kramer Junction site.

The power plant can be provided by most steam turbine vendors.

CSP Resource Potential for San Diego Region

NREL GIS Screening Analysis

NREL performed a screening analysis to look for regions with the best potential for siting of large CSP plants in the southwestern United States. The screening analysis was performed using geographic information systems (GIS) to identify areas with high potential for CSP development. The GIS analysis evaluated the following factors to determine siting potential: direct normal solar resource level, land slope, environmental sensitivity, and contiguous area.

Parabolic trough solar power plants require high direct normal insolation (DNI), or beam radiation, for cost-effective operation; the required size of the solar field for a given power plant capacity is in general directly proportional to the DNI level. The new Perez satellite derived solar resource data was used to identify the level of direct normal solar resource[11].

In general, a parabolic trough solar power plant in a good solar resource region requires approximately 5 acres (20,000 m^2) per MW of plant capacity. Plants with thermal storage and higher capacity factors will require proportionally more land per MWe. Siting studies have generally found that land with an overall slope of less than 1% are the most economic to develop to minimize grading costs. The siting analysis looked for land with a slope of less than 1%.

The federal government owns the majority of the land in desert areas having a high solar resource. Some of these land areas are incompatible with development, because they are in national parks, national preserves, wilderness areas, wildlife refuges, water, or urban areas. A federal land classification dataset produced by the U.S. Geological Survey (USGS) was used to identify areas that should be eliminated from the analysis because of this incompatibility. Urban areas and water features were identified using a USGS global land cover/land classification dataset and other publicly available data sources. In general, Bureau of Land Management (BLM), National Forrest Service, and Department of Defense lands were assumed to be acceptable for purposes of this screening study.

[11] Perez, R.; Ineichen, R.; Moore, K.; Kmiecik, M.; Chain, C.; George, R.; Voignola, F. (2002): "A New Operational Satellite-to-Irradiance Model, Solar Energy 73, 5 pp. 307-317.

After the solar resource level, percent slope, and compatibility have been accounted for, an area must be at least 8 km^2 in size. This area would be sufficient for the development of a 400-MW plant. Some developable areas may have been excluded in the analysis because of small gaps that caused the areas to appear discontinuous.

Maps were generated that show regions that meet the criteria listed above. High voltage transmission lines, substations, and other power plants are overlaid to help identify regions that might represent good solar sites. NREL used the PowerMap (©Platts 2002) dataset to determine the location of the high voltage transmission lines (115kV and higher) and existing power plants. A DNI value of 6.75 $kWh/m^2/day$ of average annual solar irradiance was the minimum DNI level considered. Figure D.15 shows the final results of the map generated for the southwest. Although it appears that most of the high resource regions have been eliminated, a substantial resource potential remains. Table E.4 lists the area and the approximate solar capacity that could be generated for the southwestern states. Note that the resource potential represents a huge amount of solar capacity, many times the current US total electric capacity. However, one will also note that much of the identified lands (Imperial Valley, CA for example) are agricultural lands that are currently in use. It is also important to note the potentially huge resource potential in Northern Mexico. Although some resource potential exists in San Diego County, most of this appears to be in a valley surrounded by mountains. Imperial Valley probably represents the preferred location.

Figure E.15: CSP Siting Study Map for the Southwestern U.S

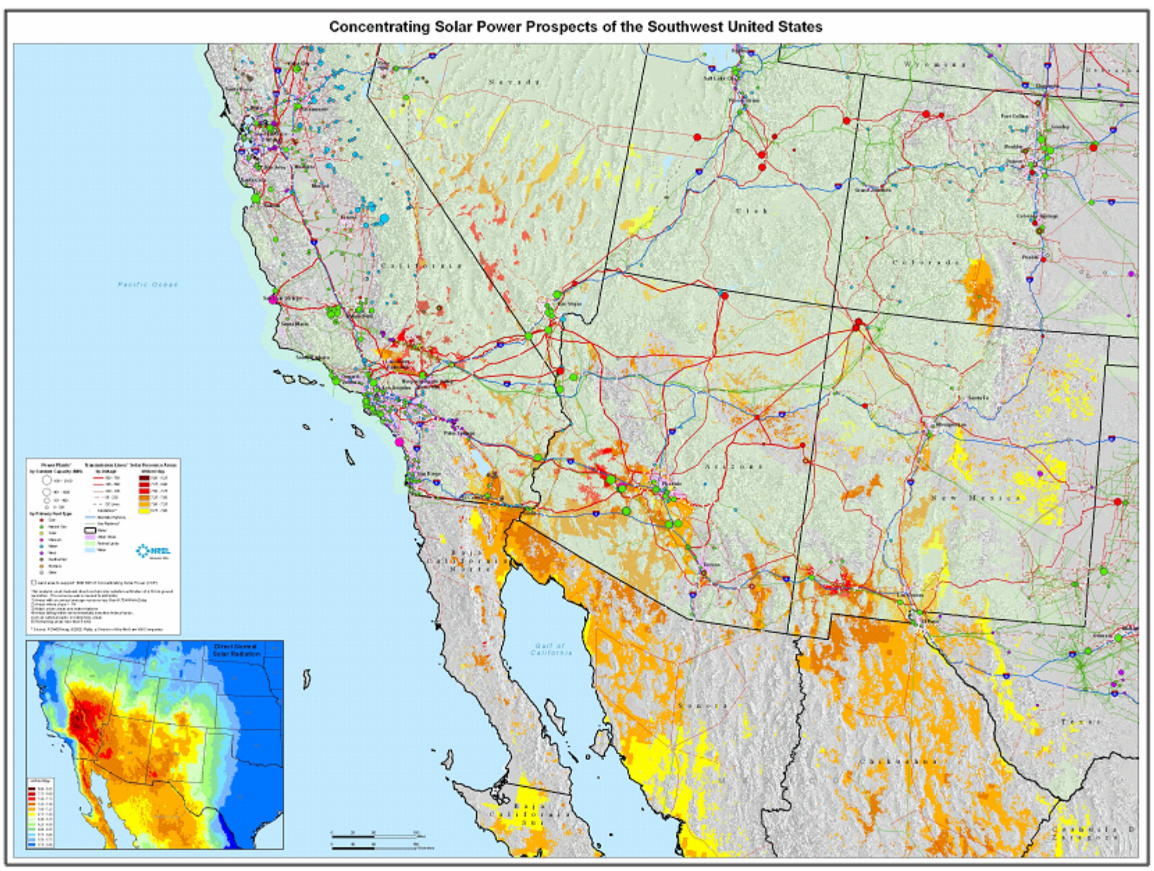


Table E.4: Solar Siting Analysis Results – (Solar Resource > 6.75 kWh/m^2-day)

State	Area (km^2)	Approximate Solar Capacity (GW)
Arizona	49,900	2,500
California	17,700	885
- San Diego	130	6
- Imperial	5,800	290
Colorado	5,500	275
Nevada	14,500	725
New Mexico	39,300	1,965
Utah	3,000	150
Total	129,900	6,500

Economics of Central Station Solar

This section looks at the economics of central station parabolic trough solar power plants.

Trough Plant Configurations

There are a number of parabolic trough plant configurations that might be considered for near-term applications. These include the following:

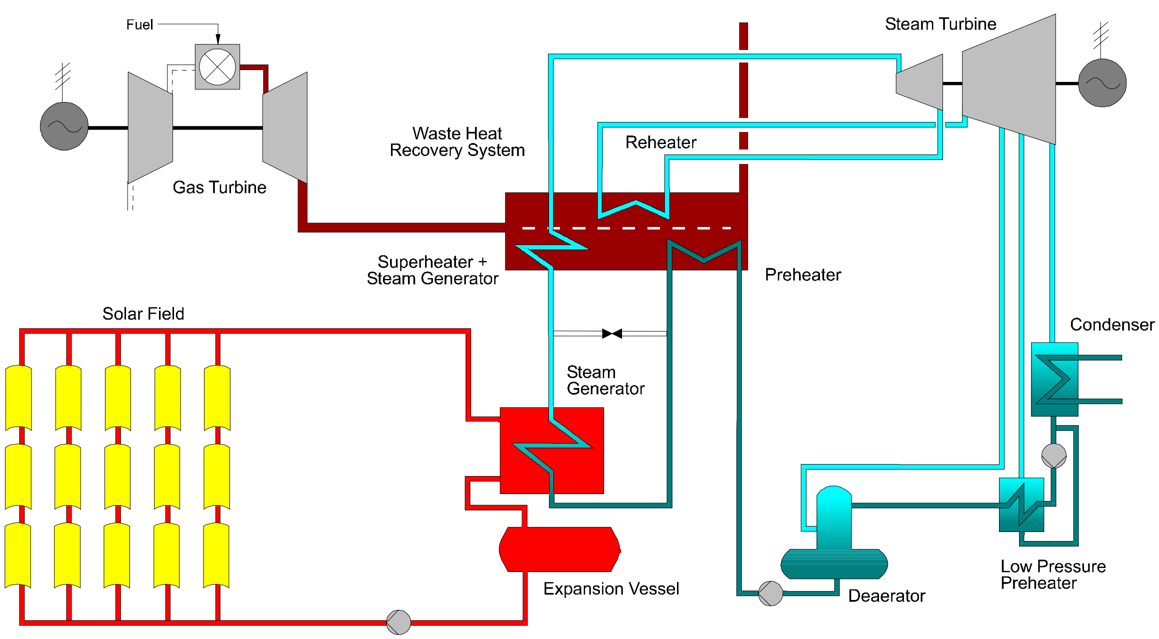
Solar Only: These plants can operate only with solar energy. They have no backup fossil firing capabilities or thermal energy storage. The 50-MWe trough plant under development by SolarGenix in Nevada is a solar-only plant.

Solar/Hybrid: Eight of the nine existing SEGS plants are hybrid plants. Their natural-gas-fired boilers or HTF heaters allow them to operate with fossil energy to augment solar generation or when solar energy is not available. The SEGS plants are qualifying facilities under PURPA, and they are allowed to use up to 25% natural gas input to the plant. However, given the high heat rate of steam plants operating on natural gas, it is unlikely that in the future a hybrid trough plant would burn natural gas for anything other that on-peak or emergency generation.

Thermal Energy Storage: The first SEGS plant included 3 hours of thermal energy storage that allowed the plant to dispatch solar output to meet the SCE summer and winter peak periods (the original contract had a winter peak from 5 to 9 pm). Until recently, no TES technology existed for parabolic trough plants that operate at 735^{o}F. A new TES option has been developed based on the molten-salt thermal energy storage system used at the Solar Two demonstration project. This system uses a conventional HTF in the solar field and has a heat exchanger that is used to charge and discharge the molten-salt storage system. The two 50-MWe trough plants currently under development by Solar Millennium in Spain will include 6 to 9 hours of molten-salt TES.

Integrated Solar Combined Cycle System: The ISCCS configuration (Figure E.16) integrates a trough solar plant into the bottoming cycle of a combined-cycle plant. The primary advantage of the ISCCS is that the incremental cost of increasing the bottoming cycle is less than the cost of a stand-alone steam power plant. The disadvantage of the ISCCS is the added complexity of integrating the solar and gas. In the most aggressive case, the steam turbine output is doubled when solar energy is available. The ISCCS allows solar energy to be used to generate steam and to use the waste heat from the gas turbine for preheating and superheating the steam. This typically increases the bottoming cycle efficiency. Unfortunately, when solar energy is not available, the bottoming cycle will run at part load, impacting the gas mode efficiency. ISCCS plants typically have very low solar contributions, on the order of 1% to 15% of annual output for a baseload combined-cycle plant. No ISCCS plants have been built. ISCCS plants are currently planned for all four of the GEF projects in India, Egypt, Morocco, and Mexico and for a plant under consideration in Algeria. We believe ISCCS plants are a niche opportunity and it is unlikely that a new ISCCS plant would be built in California. However, a number of combined cycle plants have been built with excess steam turbine capacity for use with duct burning. The duct burning capacity of these plants could potentially be repowered with a trough solar field.

Figure E.16: Process Flow Diagram for Integrated Solar Combined Cycle System (ISCCS)



Direct Steam Generation (DSG) Plants: In this configuration, high-pressure steam is produced directly in the solar field. This eliminates the need for the HTF system and allows higher temperatures than those possible with current heat transfer fluids. This concept has been field-prototype tested with encouraging results, but it is not ready for commercial deployment at this time.

Trough Organic Rankine Cycle (ORC) Plants: This configuration integrates a trough solar field with a binary organic Rankine cycle power plant optimized for solar operating temperatures. Arizona Public Service has contracted with SolarGenix to build a 1-MW trough ORC plant. Other trough ORC plants that have been proposed range in size from 100 kWe to 5 MWe. This configuration is not being considered in this study, but some benefits may accrue as a result of these developments, because these plants are intended to be fully automated with no dedicated operations crews. Also, dry cooling and hybrid wet/dry cooling technologies are being evaluated for these systems.

Plant Technology Assumptions

This section considers two time frames for building parabolic trough power plants. It begins by looking at designs that might be used immediately for new parabolic trough power plants and then at those that might be built in the five-year time frame, based on technologies that are currently under development.

Near-Term Plants

The technologies and designs assumed in the near term must have previously been demonstrated or otherwise considered ready for commercial application. These plants could begin being constructed and be on line by 2007 to 2008. For the economic assessment, we will consider three potential near-term parabolic trough plant configurations: solar only, hybrid, thermal storage, and repowering of duct burner capacity of a combined cycle plant.

In the past, trough plants were limited in size to 30 MWe by PURPA regulations for qualifying facilities. Later, this limit was raised to 80 MWe and eventually eliminated completely. The optimum size for a trough plant was thought to be somewhere between 120 and 200 MWe by Luz. Changes in the solar field piping by eliminating flex hoses and replacing them with ball joints have significantly reduced the pumping parasitics for new trough plants. For purpose of this study, we assume a plant size of 100 MWe as the baseline system size. The 200 MWe size is clearly feasible, the main concern is assuring the existing supply of mirrors and receivers is sufficient to build a plant of that size. There is a significant economy of scale in the larger power plant size and in the O&M crew. Larger turbine generators are cheaper on a per-kilowatt basis. Another advantage to larger sizes is that US supply of the turbine becomes possible. Smaller turbines are likely to require being imported. Current currency exchange rates make purchasing a turbine from Europe relatively expensive.

Although the Luz LS-3 collector was the last one deployed at the SEGS plants, its operation and performance characteristics were not as good as the smaller Luz LS-2 collector. There is an economy of scale with collectors, so within some limit (determined by wind loads), larger collectors are expected to be cheaper. Currently, at least four different collectors that we know of are being proposed for future trough projects. For our analysis, we use the SolarGenix collector as our baseline plant assumption. This and the EuroTrough are new collector designs that attempt to improve on the Luz collectors, based on operating experience from SEGS. The SolarGenix collector is currently being tested at their test facility Boulder City, Nevada. The EuroTrough collector is being tested at the SEGS V plant at Kramer Junction.

Advances continue to be made in parabolic trough receiver technology. There are currently two suppliers of the receiver, Solel Solar Systems of Israel, and Schott Glass of Germany. Both receiver designs show a significant performance improvement over prior Luz designs based on testing at Sandia National Laboratories in Albuquerque, and the SEGS plants. Both receivers have demonstrated improved receiver reliability.

We assume the same manufacturer for mirrors (Flabeg of Germany) as the one that provided mirrors for the SEGS plants. The mirrors have not been a significant issue. Future plants are assumed to use glass or alternative mirrors.

A near-term thermal energy storage technology is currently planned for use in the 50-MWe trough plants under development in Spain. This type of thermal storage is one of the technologies currently under consideration for application in near-term projects.

Future Technology
The future technology cases show the potential impact on the cost of energy for technologies that are currently under development. We assume that these technologies will be built starting approximately five years from now and would be on line starting in 2012. These future power plant configurations are assumed to be a solar only or solar with thermal storage. They are assumed to be 100 to 200 MWe in size (although larger sizes may be possible). We assume that the parabolic trough collector technology will be similar to today's systems but with design improvements to reduce costs. Key among the changes will be increasing the length of the collector to 150 m. The EuroTrough collector is already this size. Also, we expect continued improvements in receiver technology as current receiver vendors and others are continuing to work on improving the selective coating. We consider a selective coating with emissivity of 0.07 at 400^{o}C.

We consider that new, cheaper thermal storage technologies are likely to be available in 5 years. We assume a low-melting-point molten salt (Hitec XL) is used as the heat transfer fluid in the solar field and thermal energy storage media. This and an improved selective coating for the receiver will allow the solar field operating temperature to be increased to 450^{o}C. This improves steam cycle efficiency and reduces HTF pumping parasitics.

Design Optimization
This section analyzes a range of parabolic trough solar field and thermal storage system sizes to determine the optimum configurations for near-term and future plants. Note that, depending on the specific figure of merit used to assess the results, different configurations would be selected as the optimum design. For example, the system with the lowest capital cost is not the system with the lowest levelized cost of energy.

Modeling Parabolic Trough Performance and Economics
Solar plants rely on an intermittent fuel supply—the sun. Therefore, it is necessary to model a plant's performance on at least an hourly basis to understand what the annual performance will be. NREL has developed a proprietary model for conducting annual performance calculations. Validation studies reproduce output from the SEGS plants within a few percentage points on an annual basis. One advantage of the NREL trough model is that capital cost, O&M costs, and financial calculations have been added directly to the spreadsheet. This allows the plant design configurations to be more easily optimized. To compare various technology options, NREL uses a real levelized cost of energy in current-year dollars. This allows clear comparisons of current and future technologies and

technologies that might not have the same lifetimes. One of the benefits of this metric is that it accounts for the financing structure and cost.

Solar Multiple and Design Point

The solar multiple is the ratio of the solar energy collected at the design point to the amount of solar energy required to generate the rated turbine gross power. A solar multiple of 1.0 means that the solar field delivers exactly the amount of energy required to run the plant at its design output at the design point solar conditions. A larger solar multiple indicates a larger solar system. The design point is the reference set of conditions selected for designing the system. Solar multiples are commonly used when designing power towers, but have not typically been used when designing the Luz trough plants likely because, with the exception of SEGS I, the plants did not have thermal storage. However, the solar multiple is a useful metric for evaluating the performance and economics of plants with a range of solar field sizes. The design point conditions used for parabolic trough systems are listed in Table E.5. They were chosen to represent a high, but not the peak, value of solar collection during a year. The design point is calculated for an incidence angle of zero degrees, which means that the sun is normal to the collector aperture. The wind speed of 5 m/s is typical of normal day time conditions in the Mojave desert. For purposes of this assessment a range of solar multiples from 1.0–3.5 were used in a parametric analysis to find the optimum plant configurations.

Table E.5: Design Point Conditions for Parabolic Trough

Metric	Value
Cos θ	0
Amb. Temp.	25 C
DNI	1000 W/m^2
Wind	5 m/s

Solar Field Configurations

Based on the design point conditions in the sections above, solar fields with solar multiples of 1.0, 1.2, 1.5, 1.8, 2.1, 2.5, 3.0, and 3.5 were evaluated. Table E.6 below shows the solar field size for each solar multiple. As mentioned above, the solar multiple has not typically been used at the existing SEGS plants. The reference conditions are somewhat arbitrary, but allow a convenient method to evaluate different solar field sizes. As a point of reference, the SEGS plants have a solar multiples of about 1.1 to 1.2 based on the existing collector performance.

Table E.6: Trough Solar Field Configurations

Solar Multiple	Area m^2
1.0	455,224
1.2	549,279
1.5	684,717
1.8	820,156
2.1	959,356
2.5	1,139,941
3.0	1,365,672
3.5	1,595,165

Plant Optimization

The following figures show the annual capacity factor, the on-peak capacity factor, and the levelized cost of energy for parabolic trough plants with different solar multiples (solar field sizes) and quantities of thermal storage.

From Figure E.17 it can be seen that parabolic trough plants can be designed to have annual capacity factors from 20% to over 60% in good solar resource regions.

Figure E.17: Annual Capacity Factor for Near-term Parabolic Trough Plan as a Function of Solar Field Size and Size of Thermal Energy Storage

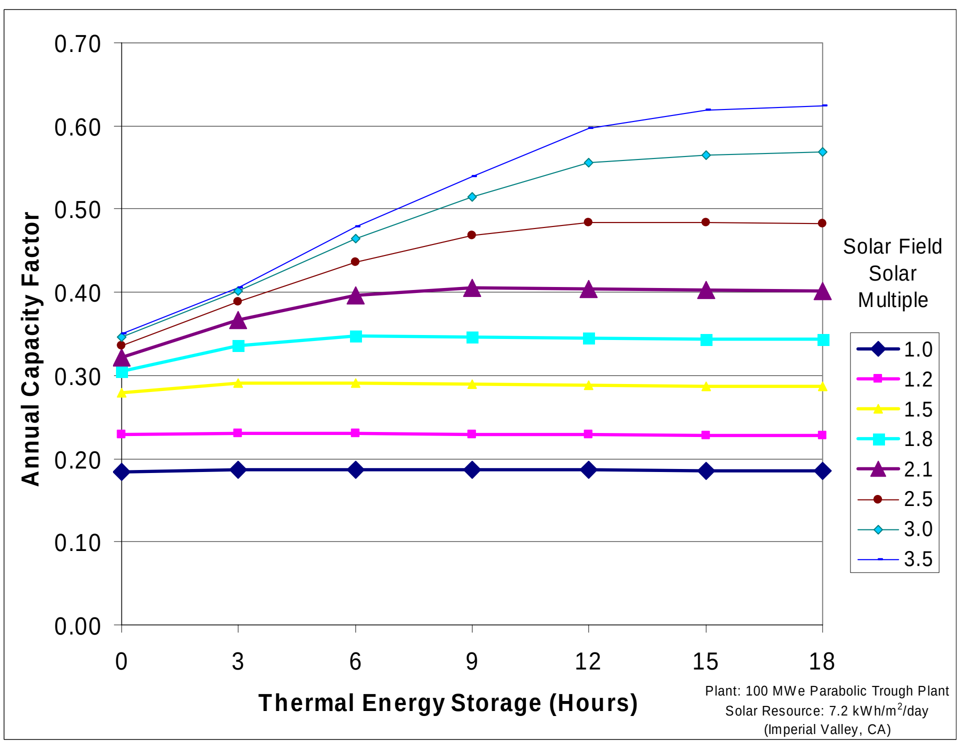


Figure E.18 shows how parabolic trough plants with various solar field sizes and amounts of thermal storage perform during the SCE summer on-peak time of use period. Trough plants without thermal energy storage and a solar multiple of 1.1 would be expected to achieve about 80% on-peak capacity from solar energy. This is what the SEGS plants report in. However, by adding thermal storage or increasing the solar field size, the annual on-peak capacity factor can be increased to 100% from solar energy alone.

Figure E.18: On-Peak Capacity Factor as a Function of Solar Field Size and Thermal Storage Capacity

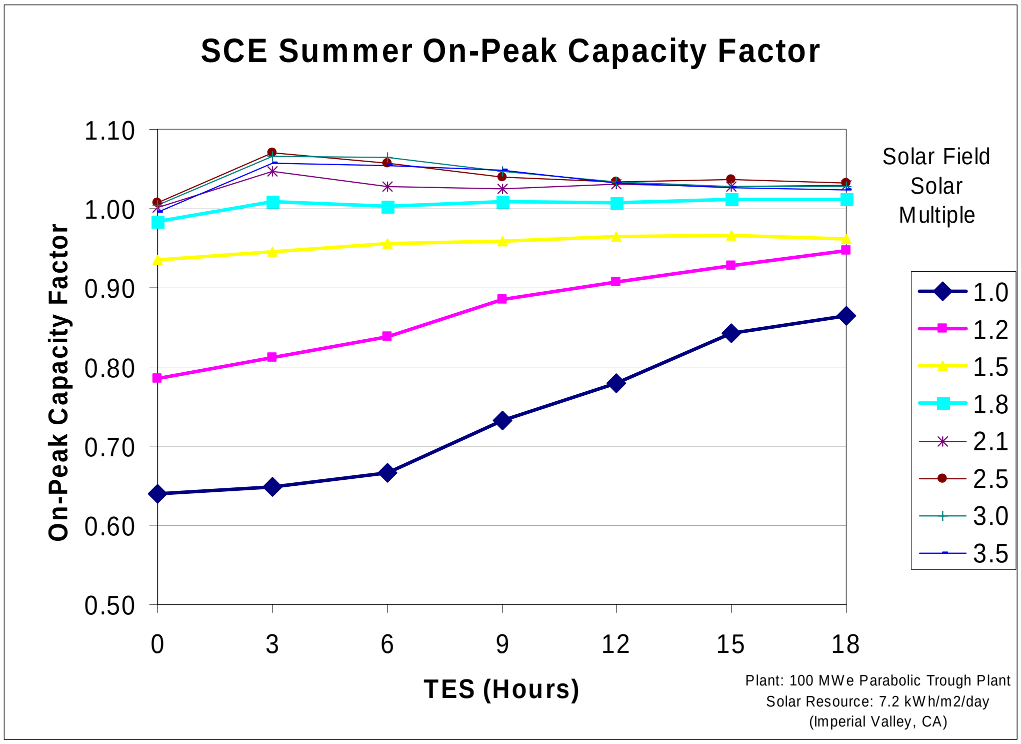
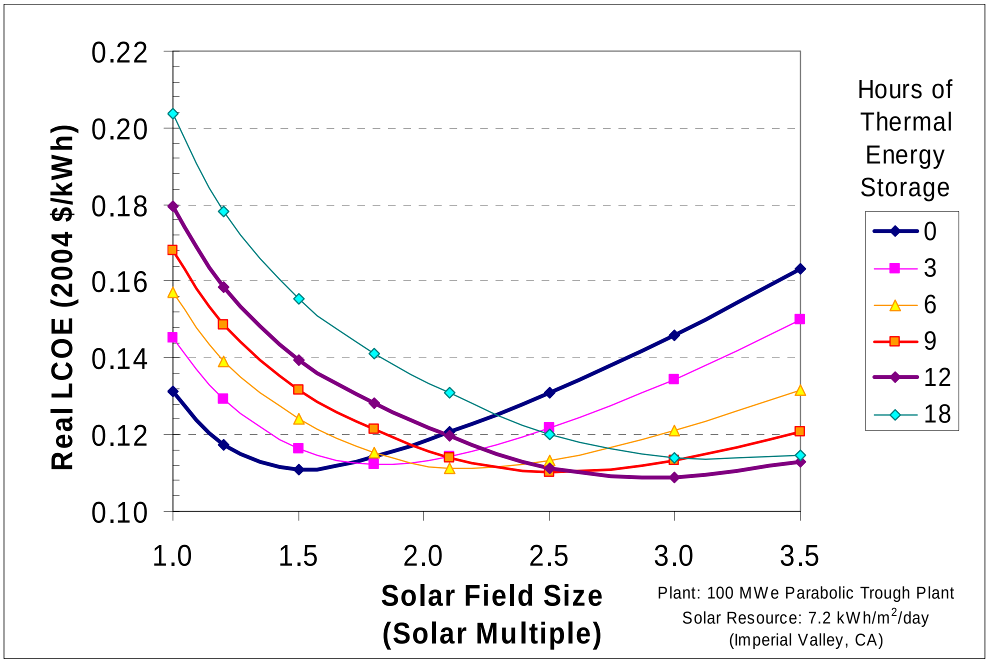


Figure E.19 shows the real levelized cost of energy in 2004 dollars for near-term parabolic trough plants with different sizes of solar field and amounts of thermal storage. From the figure the minimum cost of energy from a plant with no thermal energy storage occurs with a solar multiple of about 1.5. The lowest cost of energy for a plant with thermal storage occurs with 12 hours of thermal energy storage and a solar multiple of about 2.5. However, the minimum cost of energy does not vary much for plants with 6 to 12 hours of thermal energy storage. Because the storage technology is relatively untested, we have selected a system with 6 hours of thermal energy storage and a solar multiple of 2.0 for our near-term plant with thermal energy storage. Future plants with thermal storage are assumed to have 12 hours of storage and a solar multiple of 2.5.

Figure E.19: Levelized Cost of Energy as a Function of Solar Field Size and Thermal Storage Capacity



SDG&E Design Study Assessment

Table E.7 shows the key design parameters for each of the near-term and future parabolic trough power plant configurations that are evaluated in this study.

Table E.7: Trough Plant Configuration and Design Assumptions

Case	Ref.	Next Plant Technology			Future Technology		
Project	SEGS VI Hybrid 30	Trough Solar/ Hybrid 100	Trough 6-hrs TES 100	Trough Re-power 100	Trough Solar 200	Trough 6-hrs TES 200	Trough 12-hrs TES 200
In Service	1989	2007	2007	2007	2012	2012	2012
Solar Field							
Solar Multiple	1.1	1.5	2.1	1.5	1.5	2.0	2.8
Solar Field Size (km^2)	0.19	0.69	0.96	0.69	1.28	1.64	2.31
Land Area (km^2)	0.65	2.3	3.2	2.3	4.3	5.5	7.8
Heat Transfer Fluid	VP-1	VP-1	VP-1	VP-1	VP-1	Hitec XL	Hitec XL
Solar Field Temp. (F)	560-735	560-735	560-735	560-735	560-735	560-842	560-842
Collector							
Aperture, m	5	5	5	5	5.75	5.75	5.75
Length, m	50	100	100	100	150	150	150
Receiver							

Absorptance	0.93	0.96	0.96	0.96	0.96	0.96	0.96
Emittance @ 400C	0.15	0.14	0.14	0.14	0.07	0.07	0.07
Envelope Transmittance	0.935	0.965	0.965	0.965	0.97	0.97	0.97
Bellows Shadowing	0.971	0.971	0.971	0.971	0.99	0.99	0.99
Thermal Energy Storage							
Storage Capacity (hrs)	0	0	6	0	0	6	12
Thermal Storage Media	NA	NA	Solar Salt	NA	NA	Hitec XL	Hitec XL

Parabolic Trough System Performance
Table E.8 lists the performance of current, near-term, and future parabolic trough plants. Initial performance improvements are based on those that have already been demonstrated in field-testing. These include the use of the new Solel receiver and the replacement of flex hoses with ball joints, which will significantly reduce HTF pumping parasitics. Future efficiency gains are assumed to come from further improvements in the receiver selective coating and through increased solar field operating temperatures, which in turn lead to improved power cycle efficiency and further reductions in HTF pumping parasitics. The addition of thermal storage means that the solar field size can be increased, which results in increased annual capacity factors. Thermal storage also allows the power plant to operate closer to its design efficiency more of the time, and less energy is dumped also, fewer power plant start-ups are required per unit of generation.

Although the original SEGS plants were designed to use 25% natural gas, given the high heat rate of these plants, it is assumed here that the natural gas backup is only used to supplement solar production during the on-peak period. This increases the on-peak generation above a 100% capacity factor, but only increases the annual capacity factor by 2%. For purposes of this assessment, the repowered option is assumed to have similar performance to the solar only trough plant. In reality, the solar generation could be higher or lower depending on the efficiency of the steam cycle when solar is added.

Table E.8: Trough Performance Summary

	Baseline	**Next Plant Technology**			**Future Technology**		
Imperial Valley Solar Resource 7.2 kWh/m^2/day	**SEGS VI Hybrid 30**[a]	**Trough Solar/ Hybrid 100**	**Trough 6-hrs TES 100**	**Trough Repower 100**	**Trough Solar 200**	**Trough 6-hrs TES 200**	**Trough 12-hrs TES 200**
In Service	1989	2007	2007	2007	2012	2012	2012
Plant Performance							
Net Power (MWe)	30	100	100	100	200	200	200
Annual Capacity Factor (%)	22/34	28/30	40	28	30	42	59
SCE On-peak Capacity (%)	88/ 100+	93/100 +	100+	93	96	100+	100+
Solar Mode Efficiency							
Optical Efficiency	0.533	0.698	0.698	0.698	0.720	0.720	0.720
Receiver Thermal Losses	0.729	0.791	0.791	0.791	0.883	0.863	0.863
Piping Thermal Losses	0.961	0.969	0.969	0.969	0.965	0.970	0.970
Storage Thermal Losses	--	--	0.994	--	--	0.998	0.997
Dumped Energy	--	0.911	0.951	0.911	0.950	0.950	0.950
Power Plant Efficiency	0.350	0.364	0.368	0.364	0.364	0.392	0.392
Electric Parasitic Load	0.827	0.875	0.881	0.875	0.890	0.927	0.929

Power Plant Availability	0.98	0.94	0.94	0.94	0.94	0.94	0.94
Annual Solar-to-Electric Efficiency	10.6%	12.6%	13.3%	12.6%	15.6%	16.9%	17.1%
Notes: a) Based on actual Kramer Junction solar and operating data for 1999. No scheduled outage was taken at SEGS VI during 1999.							

System Capital Cost

Table E.9 gives the capital cost of the major systems in each trough plant configuration. Near-term costs are based on cost models developed in collaboration with various industry partners. We believe these costs are reasonably consistent with the prices currently being listed by industry. Future costs reflect technology advances, but do not include any additional cost reduction. In fact, some additional cost reduction would be expected.

Table E.9: Trough Capital Cost Summary

Case	Next Plant Technology			Future Technology		
All prices in thousands 2004 Dollars	Trough Solar/ Hyb 100	Trough 6-hrs TES 100	Trough Repower 100	Trough Solar 200	Trough 6-hrs TES 200	Trough 12-hrs TES 200
In Service	2007	2007	2007	2012	2012	2012
Direct Capital Cost (k$)						
Structures & Improvements	2,239	2,452	2,239	2,683	2,932	3,357
Collector System	165,978	229,992	165,978	278,750	356,230	494,433
Thermal Storage System	0	51,287	0	0	70,165	130,337
Steam Gen or HX System	9,056/ 10,900	9,997	9,056	13,742	14,839	16,679
Aux Heater/Boiler	0/16,751	0	0	0	0	0
EPGS	38,754	38,754	0	62,956	62,956	62,956
Balance of Plant	22,533	22,533	0	36,605	36,605	36,605
Total Direct Costs	238,560/ 257,155	355,015	177,273	394,735	543,728	744,367
Contingency on Direct Costs (mult.)						
Structures & Improvements	0.20	0.20	0.20	0.20	0.20	0.20
Collector System	0.10	0.10	0.10	0.10	0.10	0.10
Thermal Storage System	0.10	0.10	0.10	0.10	0.10	0.10
Steam Gen or HX System	0.10	0.10	0.10	0.10	0.10	0.10
Aux Heater/Boiler	0.10	0.10	0.10	0.10	0.10	0.10
EPGS	0.10	0.10	0.10	0.10	0.10	0.10
Balance of Plant	0.10	0.10	0.10	0.10	0.10	0.10
Other Costs (k$)						
Engr, Const, Proj Manag	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%
EPC Mark-up & Guarantee [i]	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Project Costs	0.4%	0.4%	0.6%	0.5%	0.5%	0.5%
Land Cost	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%
Sales Tax	5.8%	6.2%	6.3%	5.8%	6.2%	6.4%
Total Capital Cost (k$)	324,559/ 349,712	478,009	240,514	537,172	732,986	1,000,7 41

$/kW (w/o Land)	3,234/ 3,486	4,764	2,394	2,675	3,651	4,984
Collector Cost ($/m^2)	267	264	267	240	238	236

Notes: [i] EPC is Engineer, Procure, and Construct. Includes the EPC profit, performance warranty, and risk premium. 7% is considered reasonable for an experienced contractor and an understood technology. The New Mexico CSP Feasibility Study indicated the EPC mark-up could be 15% or more on the next trough plant built.

Operation & Maintenance Costs

NREL has worked with KJC Operating Company to develop an O&M cost model for parabolic trough plants. Table E.10 presents the O&M costs for the near-term and future trough plant cases.

Table E.10: Trough Operation & Maintenance Cost Summary

Case		**Next Plant Technology**			**Future Technology**		
Costs in 2004$		Trough Solar/ Hybrid 100	Trough 6-hrs TES 100	Trough Repower 100	Trough Solar 200	Trough 6-hrs TES 200	Trough 12-hrs TES 200
In Service		2007	2007	2007	2012	2012	2012
O&M Labor Details							
Administrative	Staff	7.0	7.0	1.8	7.0	7.0	7.0
Operations	Staff	13.7	14.8	3.7	16.1	18.1	21.1
Power Plant Maintenance	Staff	8.0	8.0	2.0	8.0	8.0	8.0
Solar Field Maintenance	Staff	9.2	12.5	9.2	16.3	22.2	31.2
	Staff	38.0	42.3	16.7	47.4	55.3	67.3
Ave. Annual Rate (loaded)	$k/yr	60.3	59.3	51.2	58.4	60.2	59.0
Non-Labor Costs							
HCE Spares Cost	$k/yr	751	1052	751	699	968	1380
Non-receiver SF Spares	$k/yr	350	491	350	618	855	1220
PB & BOP Spares & Mats	$k/yr	320	531	51	511	805	1061
Service Contracts	$k/yr	175	219	140	273	353	474
Water Cost	$k/yr	150	212	150	317	430	613
Miscellaneous	$k/yr	306	348	145	403	481	601
Capital Equipment List	$k/yr	134	187	134	249	345	491
	$k/yr	2,185	3,040	1,721	3,069	4,237	5,840
O&M Costs							
Labor Cost	$k/yr	2,746	3,014	850	3,323	3,994	4,766
Materials & Services Cost	$k/yr	2,623	3,648	1,954	3,683	5,338	7,358
Annual Fuel Cost	$k/yr	0/492	0	0	0	0	0
Total Annual O&M Cost	$k/yr	5,368	6,662	2,804	7,007	9,332	12,124
	$/kWhe	0.022	0.019	0.011	0.013	0.013	0.012

Financial Methodology

In order to determine the cost of electricity from a solar power plant, a 30-year cash flow analysis is performed. The analysis accounts for all the costs in the project, including such factors as the initial capital cost, O&M costs, fuel costs, insurance, taxes, financing and management fees, loan repayments, and return on investment to the owners. Key to getting realistic results is the use of appropriate assumptions in the analysis. Power industry financial experts and parabolic trough developers were contacted to determine appropriate financial parameters for the analysis discussed here. Table E.11 shows the baseline financial assumptions used for a trough plant built in California. A more detailed discussion of project finance for parabolic trough plants is presented in[12].

Table E.11: Solar Plant Financing Assumptions

Project financial life	30-year
Equity internal rate of return	IPP – 15%, Utility – 12%
Debt interest rate	6%,
Debt term	20-year
Debt service coverage ratio	1.40
Construction loan	7%
Construction period	2-years
Annual insurance cost	0.5% of capital cost
Accelerated depreciation	5-year MACRS
Federal Investment Tax Credit	10%
Property taxes	California solar property exemption
Inflation	2.5%
EPC Mark-up	7%
Owner Costs	3%

For purposes of comparing technologies and financial options, we include three financial metrics for each case: the first-year PPA price and escalation rate, then nominal levelized cost of energy (LCOE), and the real LCOE in 2004 dollars. In the financial analysis we determine the minimum real cost of energy by varying the first-year PPA price, PPA price escalation rate, and project debt fraction; while assuring other financial constraints such as the minimum debt service coverage ratio are maintained. This allows all financial requirements to be met while minimize the cost of electricity over the life of the project. The nominal LCOE is similar to the MPR and can be used to evaluate the competitiveness of the solar plant to the fossil proxy plant.

Table E.12 shows the financial results for the near-term and future parabolic trough plant configurations defined in the sections above.

Table E.12: Trough Base Case Financial Results

	Next Plant Technology			Future Technology		
Plant Site: Imperial Valley 7.2 kWh/m2/day	Trough Solar/ Hybrid 100	Trough 6-hrs TES 100	Trough Re-powered 100	Trough Solar 200	Trough 6-hrs TES 200	Trough 12-hrs TES 200
In Service	2007	2007	2007	2012	2012	2012
Plant Performance						
Annual Capacity Factor	27.9/ 28.7%	39.6%	27.9%	29.9%	42.0%	59.9%

[12] Kistner, R., and H. Price, 1999, “Financing Solar Thermal Power Plants Proceedings of the ASME Renewable and Advanced Energy Systems for the 21st Century Conference, April 11-14, 1999, Maui, Hawaii.

Natural Gas Use (Btu/kWh)		3.04				
Plant Capital Cost						
Capital Cost ($/kWe)	3,234/ 3,486	4,764	2,394	2,675	3,651	4,984
Land Cost (thousands $)	1,142	1,598	1,142	2,126	2,944	4,196
Operating Costs						
Non-Fuel Variable O&M ($/MWh)	2.72	2.47	1.70	1.88	1.79	1.68
Fixed O&M ($/kW-yr)	47.87	58.05	23.89	30.11	40.06	51.80
Insurance (k$/yr)	1,743	2,382	1,197	2,675	3,837	5,303
Financial Model Results ($/kWh)						
First Year PPA Price	0.144/ 0.151	0.145	0.102	0.107	0.108	0.104
PPA Escalation	1.29/ 1.20%	1.25%	1.21%	1.23%	1.22%	1.21%
DOE Metric Real Levelized Cost of Energy (LCOE) 2004$	0.111/ 0.115	0.111	0.078	0.082	0.083	0.079
Nominal LEC (Market Price)	0.165/ 0.171	0.166	0.116	0.122	0.123	0.118
Debt %	60%	60%	60%	60%	60%	60%

All cases assume IPP financing with 30 year-15% IRR on equity, and 20 year debt with 6.0% interest rate.

Parametric Analysis on Assumptions

In this section we look at the sensitivity of the required PPA contract price to various parameters: resource level, PPA term, project financing structure, and various tax incentives. For this parametric analysis, we consider only the trough plant technology cases without storage, both next plant and future technology cases, because the trends between the other technology cases are very similar.

Solar Resource Level

Table E.13 shows the influence of the site solar resource level on the first year energy price for near-term and future trough technology. Carissa Plains represents one of the best solar sites in the central valley of California. Kramer Junction is the site of five of the SEGS plants in the Mojave Desert, is one of the best known sites in California. Note that the analysis only changed the solar resource and did not change other siting considerations such at grading requirements, transmission access, and water costs. Site-specific costs could have a significant influence on the cost of power.

Table E.13: Effect of Solar Radiation Resource on Cost of Power

	Next Plant Technology			**Future Technology**		
	Trough Solar 100 W/o TES			Trough Solar 200 W/o TES		
In Service	2007	2007	2007	2012	2012	2012
Site	Carissa Plains	Imperial Valley	Kramer Junction	Carissa Plains	Imperial Valley	Kramer Junction
Solar Resource (kWhr/m^2/day)	6.564	7.203	8.054	6.564	7.203	8.054
Annual Capacity Factor	24.2%	27.9%	29.7%	25.9%	29.9%	31.7%
Financial Model Results ($/kWhr)						

First Year PPA Price	0.166	0.144	0.135	0.124	0.107	0.101
PPA Escalation	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%
Real LCOE (2004$/kWh)	0.127	0.111	0.104	0.095	0.082	0.077
Nominal LCOE ($/kWh)	0.190	0.165	0.155	0.141	0.122	0.115
Debt %	60%	60%	60%	60%	60%	60%
Nominal LEC Relative to Baseline	115%	100%	94%	116%	100%	94%

All cases assume IPP financing with 30 year-15% IRR on equity, and 20 year debt with 6.0% interest rate.

Power Plant Size, and Power Parks

Table E.14 shows the influence of power plant size on the first year energy price for near-term trough technology. The price of electricity is 15% higher for a 50 MWe plant compared to the 100 MWe baseline plant. Scaling up to 200 MWe reduces the cost of electricity by an additional 10%. Building multiple plants as a power park has the potential to reduce the cost of power. Assuming a 10% reduction in capital and O&M costs and a 25% reduction in development costs, for a four by 100 MWe solar power park, the cost of electricity would be reduced by approximately 10% over a single 100 MWe plant.

Table E.14: Effect of Power Plant Size on Cost of Power

	Next Plant Technology Trough Solar w/o TES			
In Service	2007	2007	2007	2007
Power Plant Size	50 MWe	100 MWe	200 MWe	4 x 100 MWe
Financial Model Results ($/kWhr)				
First Year PPA Price	0.166	0.144	0.129	0.127
PPA Escalation	0.014	0.013	0.012	0.013
DOE Metric Real Levelized Cost of Energy (LCOE) 2004$	0.129	0.111	0.099	0.098
Nominal LEC (Market Price)	0.193	0.165	0.147	0.146
Debt %	60%	60%	60%	60%
Nominal LEC Relative to Baseline	117%	100%	89%	88%

All cases assume IPP financing with 30 year-15% IRR on equity, and 20 year debt with 6.0% interest rate.

Dry Cooling

Table E.15 shows the influence of cooling technologies on the energy price for near-term trough technology. The analysis is based on assumptions from the recent CEC study [13]. Switching from wet to dry cooling increases the cost of power by 14%.

[13] California Energy Commission, 2002, "Comparison of Alternative Cooling Technologies for California Power Plants Economics, Environmental and Other Tradoffs," CEC 500-02-079F, Feb 2002. http://www.energy.ca.gov/pier/final_project_reports/500-02-079f.html.

Table E.15: Effect of Dry Cooling on Cost of Power

	Next Plant Technology Trough Solar 100MW w/o TES	
	Baseline Wet Cooling	**Dry Cooling**
In Service	2007	2007
Power Plant Size	100 MWe	100 MWe
Financial Model Results ($/kWhr)		
First Year PPA Price	0.144	0.164
PPA Escalation	0.013	0.013
DOE Metric Real Levelized Cost of Energy (LCOE) 2004$	0.111	0.126
Nominal LEC (Market Price)	0.165	0.188
Debt %	60%	60%
Nominal LEC Relative to Baseline	100%	114%

All cases assume IPP financing with 30 year-15% IRR on equity, and 20 year debt with 6.0% interest rate.

Cost Reduction Through Learning

The experience curve, also referred to as a learning curve, describes how unit cost decreases with increases in cumulative production[14]. A unique characteristic of the experience curve is that the cost declines by a constant percentage with each doubling of the total number of units produced. The experience curve phenomenon was first observed with aircraft production, but has since been found to hold true for many products including automobiles, calculators, computer chips, power plants, and renewable power technologies. In 1999, Enermodal used experience curves in a study for the World Bank to evaluate the cost reduction potential for parabolic trough plants[15]. This study found that an approximate 15% reduction in the levelized cost of energy occurred with every doubling of cumulative capacity. This assessment was based on the projected cost and performance of the SEGS plants. The World Bank assessment did not separate out the effects of learning and economies of scale, or technology advancements.

Sargent & Lundy conducted a study for the U.S. Department of Energy to determine the potential for future cost reduction of large central station solar technologies[16]. Cost reduction due to learning was found to be an important factor in the future cost of this technology. For this analysis, the future 200 MW case without thermal storage is used to look at the influence of learning on the future cost of power. We assume that 10% learning rate for the solar field and a 5% learning rate for the power plant and BOP for every doubling of cumulative installed capacity. We assume the starting point is 500 MW of installed capacity and that the one doubling occurs at 1000 MW, then 2000 MW and again a 4000 MW. Although steam

[14] Neij, L., 1997, "Use of experience curves to analyse the prospects for diffusion and adoption of renewable energy technology," Energy Policy, Vol. 23. No. 13, pp. 1099-1107, Elsevier Science Ltd, Great Britain, 1997.

[15] Enermodal, 1999, "Cost Reduction Study For Solar Thermal Power Plants – Final Report," Report prepared for: The World Bank, Kitchener, Ontario, Canada, May 5, 1999.

[16] Sargent & Lundy, LLC. (May 2003): Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance, SL-5641, Chicago, IL.

cycle power plant technology is a relatively mature technology in itself, solar power plants are currently a custom niche application, which still offers some opportunity for standardization. Table E.16 shows the potential influence of learning resulting from three doublings of cumulative installed capacity.

Table E.16: Effect of Learning on the Cost of Power

	Advanced Plant Technology Trough 200MW Solar Only w/o TES			
In Service	2012	2012	2012	2012
Cumulative Capacity Installed	500 MW	1000 MW	2000 MW	4000 MW
Financial Model Results ($/kWhr)				
First Year PPA Price	0.107	0.098	0.091	0.083
PPA Escalation	0.012	0.012	0.012	0.013
DOE Metric Real Levelized Cost of Energy (LCOE) 2004$	0.082	0.075	0.069	0.064
Nominal LEC (Market Price)	0.122	0.112	0.104	0.095
Debt %	60%	60%	60%	60%
Nominal LEC Relative to Baseline	100%	92%	85%	78%

All cases assume IPP financing with 30 year-15% IRR on equity, and 20 year debt with 6.0% interest rate.

Power Purchase Agreement Term

The Term of the PPA has a significant effect on the power purchase price. Table E.17 shows the PPA price for IPP projects with 20 and 30-year power purchase agreement terms. Reducing PPA terms to 20 years increases the Nominal LEC by about 16%.

Table E.17 Effect of Power Purchase Agreement Term on Cost of Power

	Next Plant Technology		**Future Technology**	
	Trough Solar 100 W/o TES		**Trough Solar 200 W/o TES**	
In Service	2007	2007	2012	2012
Financing Parameters				
Project Financial Life (years)	20	30	20	30
Equity Rate of Return	15%	15%	15%	15%
Debt Term (years)	14	20	14	20
Debt Interest Rate	6%	6%	6%	6%
Financial Model Results ($/kWhr)				
First Year PPA Price	0.187	0.144	0.143	0.107
PPA Escalation	0.003	0.013	0.000	0.012
DOE Metric Real Levelized Cost of Energy (LCOE) 2004$	0.139	0.111	0.104	0.082
Nominal LEC (Market Price)	0.192	0.165	0.143	0.122
Debt %	56%	60%	55%	60%
Nominal LEC Relative to Baseline	116%	100%	117%	100%

Project Financial Structure

Table E.17 shows the influence on the required first year energy price and escalation rate for three types of project financial structure: IPP project finance, standard utility financing, and municipal bond financing. Utility financing and municipal financing offer opportunities for reducing the cost of energy compared to the baseline IPP assumptions.

Table E.18: Sensitivity of Project Financial Structure

	Next Plant Technology Trough Solar 100 W/o TES			Future Technology Trough Solar 200 W/o TES		
In Service	2007	2007	2007	2012	2012	2012
Financing Parameters						
	IPP	Utility	Muni.	IPP	Utility	Muni.
Project Financial Life (years)	30	30		30	30	
Equity Rate of Return	15%	12%		15%	12%	
Debt Term (years)	20	30	30	20	30	30
Debt Interest Rate	6%	6%	5.5%	6%	6%	5.5%
Financial Model Results ($/kWhr)						
First Year PPA Price	0.144	0.144	0.119	0.107	0.107	0.088
PPA Escalation (%)	1.3%	0.3%	0.008	1.2%	0.2%	0.007
DOE Metric Real Levelized Cost of Energy (LCOE) 2004$	0.111	0.099	0.087	0.082	0.073	0.063
Nominal LEC (Market Price)	0.165	0.148	0.129	0.122	0.109	0.094
Debt %	60%	50%	100%	60%	50%	100%
Nominal LEC Relative to Baseline	100%	90%	78%	100%	89%	77%

Tax & Financial Incentives

Tax and financial incentives provide an opportunity for reducing the cost of power from solar technologies to a level where it can compete with conventional power technologies. Currently there is a 10% investment tax credit (ITC) and 5-year accelerated depreciation available for large-scale parabolic trough plants. A 5-year 1.8¢/kWh production tax credit (PTC) can also be taken in place of investment tax credit. Table E.19 shows the effect of various incentives on the cost of energy.

California offers a property tax exemption on solar equipment. Paying property tax on solar equipment would be like paying property tax on a 30-year fuel supply for a fossil fuel power plant. In a similar manner, the solar field should have a sales tax exemption. Paying sales taxes on the solar field equipment is like paying a sales tax up front on a fossil power plant's 30-year fuel supply. Elimination of sales taxes reduced the cost of electricity by 4%.

If the new 5-year 1.8¢/kWh PTC is used instead of the 10% (ITC), the cost of energy increases by 4%. If the Federal incentives allowed both the current ITC and the 10-year 1.8¢/kWh PTC similar to wind to be taken, the price of energy could be reduced by 7%. The Solar Energy Industries Association (SEIA) has proposed that the Federal ITC and 10-year PTC be doubled for solar power technologies[17]. This would reduce the cost of electricity by 21%. One novel approach is to convert the PTC to a capacity tax credit. This would allow green capacity to be valued. The capacity tax credit would provide up to a $158/kWe-year ($0.018/kWh * 8760 hours/year) payment for 10 years depending on the firm capacity demonstrated by the plant. This provides a greater benefit to the project than the 10-year PTC, and helps build firm renewable capacity.

[17] Rhone Resch, Presentation at Solar Program Review Meeting, Denver, Colorado, October 28, 2004.

One final incentive considered is an investment rebate buydown. This approach is used extensively for photovoltaic systems. A \$1/W buydown would reduce the cost of power by 25%.

Table E.19: Effect of Tax Incentives

	Next Plant Technology						
	Trough Solar 100 W/o TES						
In Service	2007	2007	2007	2007	2007	2007	2007
Incentive	Current Incentives	No Sales Tax	no ITC, 5-yr 1.8¢ PTC	10% ITC + 10-yr 1.8¢ PTC	20% ITC & 10-yr 3.6¢ PTC	Capacity Tax Credit	Invest-ment Rebate \$1/W
Financial Model Results (\$/kWhr)							
First Year PPA Price	0.144	0.138	0.149	0.134	0.112	0.111	0.107
PPA Escalation (%)	0.013	0.013	0.013	0.013	0.014	0.021	0.014
DOE Metric Real Levelized Cost of Energy (LCOE) 2004\$	0.111	0.107	0.115	0.103	0.087	0.093	0.084
Nominal LEC (Market Price)	0.165	0.159	0.171	0.154	0.130	0.139	0.125
Debt %	60%	60%	63%	54%	42%	51%	60%
Nominal LEC Relative to Baseline	100%	96%	104%	93%	79%	84%	75%

California Market Price Referent

The California Public Utility Commission has developed a methodology[18], the market price referent (MPR), for establishing the value of power produced by renewable technologies in support of the California Renewable Portfolio Standard (RPS). The MPR represents the levelized cost of energy of the appropriate conventional reference technology for same electric power product. The MPR calculation accounts for both the energy and capacity value of the power produced. For intermittent technologies such as wind power, the MPR would include only the energy component of the MPR. Given the excellent on-peak performance of existing parabolic trough solar plants (see Figure E.10), we assume the parabolic trough plants deserve both the energy and capacity portion of the MPR calculation. The CPUC methodology defines how the MPR is calculated for baseload and peaking products. The CPUC currently assumes a MPR for peaking generation of 0.1142/kWh (23.3% capacity factor[19]) and \$0.0605/kWh for baseload (92% capacity factor).

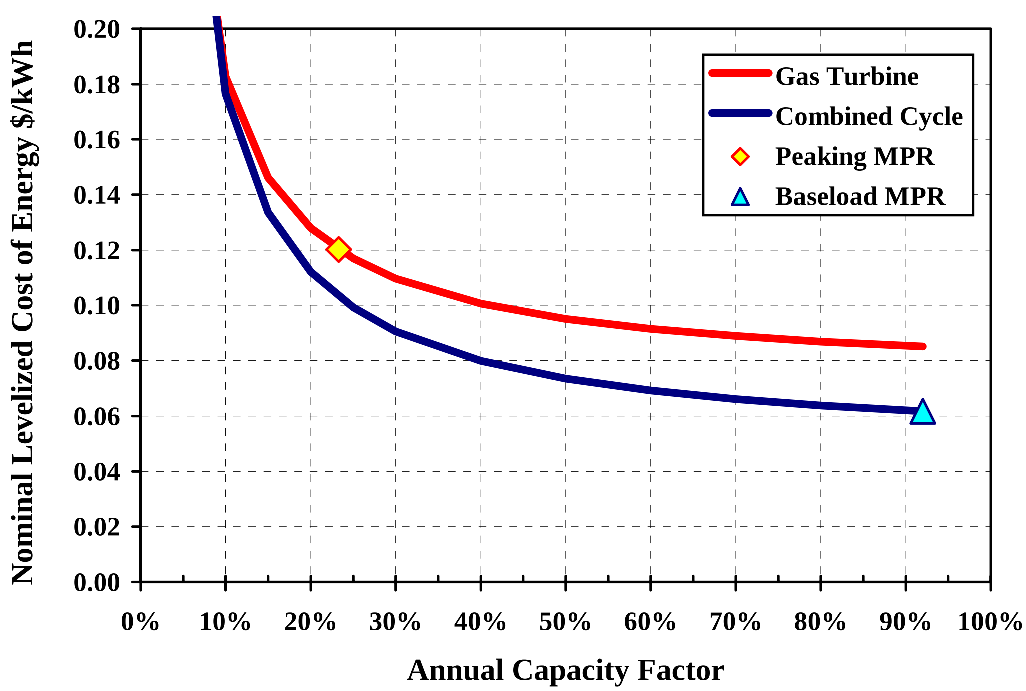
Parabolic trough plants represent an intermediate load power product, which is somewhere between a peaking and baseload technology. The MPR methodology works perfectly fine for the intermediate load case. However, for intermediate load power, annual capacity factors of 25% to 60%, it is not clear whether the gas turbine or the combined cycle represents the

[18] California Public Utility Commission, 2004, "Market Price Referent (MPR)," Decision 04-06-015, June 9, 2004. http://www.cpuc.ca.gov/static/industry/electric/renewableenergy/mpr.htm.

[19] 23.3% capacity factor based on 5 days/week, 8 hours/day, 12 months, 95% availability.

proxy plant technology. Southern California Edison developed a spreadsheet model that has been accepted as the methodology for calculating the MPR. The CPUC has developed the reference set of assumptions to be used in the MPR calculation[20]. Figure E.20 shows the MPR as a function of annual plant capacity factor for both gas turbine and combined cycle proxy technologies. The curve has been extended down to a 10% capacity factor, when in real practice; a combustion turbine would probably be the proxy system below a 15 to 20% annual capacity factor. For simplicity sake, we used a constant fuel and variable O&M cost for all capacity factors. In practice the variable cost will increase at lower capacity factors. A more exact comparison would include the time of delivery adjustments for heat rate and O&M costs for lower annual capacity factors. This would account for start-ups and operation during higher ambient temperatures having a larger impact on the heat rate. Figure E.20 also shows the peaking and baseload MPR calculations as defined by the CPUC. Our calculated peaking MPR is slightly higher than the CPUC because we used the annual price of gas and left in the capacity degradation factor that SCE had in their spreadsheet to account for reduced efficiency over time.

Figure E.20: Market Price Referent for Combined Cycle and Gas Turbine Plants



[20] California Public Utility Commission, 2005, "REVISED 2004 MARKET PRICE REFERENT (MPR) STAFF REPORT - MPR Methodology to Determine The Long-Term Market Price of Electricity for Use in California's 2004 Renewables Portfolio Standard (RPS) Power Solicitations," Rulemaking 04-04-026, February 10, 2005. http://www.cpuc.ca.gov/published/rulings/43824.htm.

Based on the assumptions uses in the analysis, a solar plant with a 28% capacity factor would have a MPR of 11¢/kWh assuming a gas turbine proxy plant and 9.2¢/kWh assuming a combined cycle proxy technology. At a 50% capacity factor the MPR would be about 9.5¢/kWh for the gas turbine proxy plant and 7.5¢/kWh for the combined cycle proxy technology. To simplify the analysis, the MPR can be broken into energy (fuel and variable O&M costs) and capacity (capital and fixed O&M costs) elements. In the analysis above, the energy payment is 7.3¢/kWh and the capacity payment is $96/kWe-year for the gas turbine proxy technology, and 4.8¢/kWh and $116/kWe-year for the combined cycle. Splitting the MPR into energy and capacity payments simplifies the analysis, once the proxy technology is selected. The capacity payment is paid for achieving the target summer on-peak capacity factor (potentially 80 or 90%), and the energy payment is paid for each kWh of electricity generated. Using the gas turbine as the proxy technology would help minimize the economic gap between the MPR and the cost of solar technology.

Development Scenarios

In order for solar plants to be built, the project must be financially attractive to investors. Depending of the specific financial structure, the revenues and incentives the project receives must be sufficient to cover the cost to build, finance and operate the project. In the longer term parabolic trough appears to have the potential to become directly economically competitive with conventional power technologies. In the near-term, additional incentives are needed to close the gap between the value of the power produced and the cost of providing that power. This section looks at a number of possible approaches or development scenarios for bridging this gap in the near-term.

The starting point is to determine the value of power from the plant. The MPR is assumed to define the value of the power to a utility. Thus if the nominal cost of power is the same as or lower than the MPR, then the project should be financially attractive compared to the fossil reference plant. For this assessment we calculate the MPR by assuming that the proxy plant is a gas turbine with a 28% annual capacity factor (11¢/kWh) or if the proxy plant is a combined cycle (9.2¢/kWh).

Table E.20 shows the Nominal LEC for a 4x100 MW solar power park located in Imperial Valley for 5 financial incentive scenarios for projects with IPP and utility financing.

Scenario 1: Current financial incentives.
Scenario 2: California exempts sales taxes for solar plants
Scenario 3: A 10-year 1.8¢/kWh Federal PTC is added to the existing incentives.
Scenario 4: The Federal ITC and PTCs are doubled.
Scenario 5: The 10-year 1.8¢/kWh PTC is converted to a $158/kW-yr capacity tax credit.

Table E.20 also shows the amount of additional upfront capital buydown that would be required ($/W) for the nominal LEC to be equal to the market price referent of 11¢/kWh or 9.2¢/kWh. Depending on the type of financing (IPP or Utility) and the incentive package available, and the MPR target, additional buydown may or may not be needed.

Table E.20: Development Scenarios

4x100 MWe Power Park Imperial Valley, CA	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**
	Current Incentives	**Add Solar Sales Tax Exemption**	**Add Production Tax Credit**	**Double ITC and PTC**	**Convert PTC to Capacity Tax Credit**
Solar Sales Tax Exemption	No	Yes	Yes	Yes	Yes
Investment Tax Credit	10%	10%	10%	20%	10%
Production Tax Credit			1.8¢/kWh	3.6¢/kWh	
Capacity Tax Credit					$158/kW-yr
IPP Financing					
Nominal LEC ($/kWh)	0.146	0.141	0.130	0.107	0.115
Buydown to Achieve MPR 11¢/kWh 9.2¢/kWh	 $0.90/W $1.35/W	 $0.75/W $1.20/W	 $0.50/W $0.90/W	 --- $0.40/W	 $0.15 $0.55
Utility Financing					
Nominal LEC ($/kWh)	0.131	0.126	0.108	0.094	0.094
Buydown to Achieve MPR 11¢/kWh 9.2¢/kWh	 $0.60/W $1.10/W	 $0.45/W $0.95/W	 --- $0.45/W	 --- $0.10	 --- $0.10

Issues/Barriers to Developers

Other Siting Considerations

A variety of other siting considerations are important to plant design and placement. Brief discussions of these factors follow.

Geology and Soils

The following data are required or useful to assess flood potential and soil characteristics for grading, foundation design, and flood diversion channels.

Topography and Surface Hydrology

- Site land area (1.5-3.0 km² depending on configuration)
- Topographical maps (1:200,000-1:500,000 for overview, 1:25,000-1:50,000 for site selection) showing slopes as a function of direction; 〈0.5% slope is preferable; higher slopes up to 3% may be acceptable depending on cost of grading; slope in the north-south direction is preferred)
- 50-year and 100-year flood data; height, duration, and season of flooding
- Aerial photographs (oblique or low-angle views)
- Data on natural drainage and flood runoff flow paths
- Information on streams, ravines, obstructions, or other special features

Soil Characteristics (at various locations on site)

- Soil type and composition as a function of depth (e.g., sand, clay, loam, sedimentary; grain size, density)
- Water table data (well depths, level of water in wells)
- Resistance to penetration (standard blows per foot)

- Lateral modulus of elasticity
- Minimum stress capacity

Geology

- Geological formation of the area
- Seismic records (magnitude and frequency data, maximum probable and maximum credible seismic events). This is needed for plant design, including buildings and solar collector field.
- Geological or man-made features that would shadow the solar field in early morning or late afternoon (features lower than 10 degrees above the tangent horizon will not shadow the solar field)

Other

- Site elevation and geographic coordinates (longitude/latitude)
- Legal description of property (location, etc.)
- Land ownership and current land use
- Land use priorities or zoning restrictions applicable to this site
- Existing rights of way (water, power line, roads, other access)
- Land cost
- Existence of dust, sand, or fumes carried to site by winds (constituents, quantity or rate, duration, direction, velocity)

Heat Transfer Fluid and Waste Products

The heat transfer fluid (HTF) for a parabolic trough solar field is typically a diphenyl/biphenyl oxide. Dowtherm A and Solutia Therminol VP-1 are commercial products that have been used in the SEGS plants. These quasi-hazardous fluids must be handled with care. Although the collector design has advanced to an excellent level of performance and reliability, occasional small spills of HTF do occur, primarily because of equipment failures. The Solar Electric Generating System (SEGS) plants at Kramer Junction have reduced HTF spills caused by accidents or pipe ruptures to very low levels. Good maintenance practices and the use of ball joint assemblies rather than flexible hoses in the HTF system are the major contributors to this improvement.

If a line worker or other staff member observes a spill or release, the system operators in the power block will be notified and the affected collector loop shut down. An appropriately equipped crew will make any equipment repairs necessary and remove any hazardous wastes to an on-site bioremediation facility that utilizes indigenous bacteria to digest the hydrocarbon contamination. A combination of nutrients, water, and aeration is provided to facilitate bacterial activity where microbes restore the soil to a normal condition in 2-3 months.

Figure E.21 shows HTF-contaminated soil being aerated with a tractor-drawn plow.

Figure E.21: Bioremediation of HTF-Contaminated Soil (Source: KJC Operating Company)

Hazardous waste or other regulated fluids and solids associated with other normal plant maintenance procedures (e.g., chemicals for water treatment; oils; cooling tower and boiler blowdown) are the same as those of a conventional power plant, or similar.
Fugitive emissions of HTF from valve stem packings and gaskets are very low and difficult to monitor. No recent measurements of fugitive losses from valves and collector field ball joint assemblies have been made at the Kramer Junction site, though this factor appears to be a very minor factor in overall HTF losses.

Regarding HTF losses, from 1996-1998 Kramer Junction did not purchase any HTF. Over that 7-year period (1996-2002), an average of about 15,000 gallons per year was purchased or just under 3% of the site inventory of 540,000 gallons.

Land Use

Solar thermal power plants require a large area for their solar collector field, as seen in Figure E.1. Approximately 5 acres are required per megawatt of electricity produced in a solar thermal power plant. As a result, the potential for wildlife habitat disruption may be greater than that of a conventional power plant. In desert regions, protected wildlife such as the desert tortoise and the Mojave ground squirrel could require habitat remediation. The 80-MWe solar thermal power facilities, SEGS VIII and IX, have minimized habitat disruption by being built on sites on former agricultural land. This strategy appears to be successful and is the wisest approach, if feasible, in regions of interest. No strategies have yet been identified for solar thermal fields that encourage dual use of land, for example, wind energy installations that include wind turbines and farming or grazing.

Desert land is valued as an unspoiled resource, but much of this land has been converted to meet human needs. Its use as a solar energy resource should rank high in evaluations. For example, compared with the land areas required for reservoirs for hydroelectric power plants, the amount of land needed for a solar field is smaller by at least an order of magnitude.

Except for the solar field, noise and visual impacts associated with solar plants are similar to those of a conventional power plant. The solar field causes no noise pollution and has minimal visual impact. Parabolic solar fields have a low profile from a normal viewing perspective.

During the certification of the SEGS plants in the Mojave Desert, some concern was expressed about reflected light that could interfere with aircraft flying in the vicinity. This was shown to be of no consequence, since the parabolic mirrors have a focal length of approximately 1 m. The reflection seen by aircraft is one sun, similar to that seen when flying over a lake.

Air Quality

Emissions will be present as a result of fossil fuel operation in hybrid mode or in combined-cycle mode, and very low emissions will result from the evaporation of the HTF ullage system and small leaks. Permitting and licensing requirements by the California Energy Commission (CEC) and the local air quality management district will dictate emissions limits to be met at the plant.

Wind

The performance and structural design of the solar field are impacted by high winds. The solar field is not designed to operate at winds of more than 35 mph; consequently, high-wind sites limit the performance potential of the solar plant. Moreover, wind forces dictate the collector structural design. Since the structure constitutes about 40% of solar field costs, it is important to optimize this component. Wind tunnel tests on parabolic trough collectors were conducted recently to provide design data for estimating design wind loads from ambient wind conditions. The solar field is designed to survive wind speeds of 80 mph with the collectors stowed in a non-operating face down position. The solar field can be designed for higher maximum survival wind speeds, but at an increased cost.

Use of Farm Land in Imperial Valley Irrigation District

One concern mentioned during the November renewable task force meeting was the use of high value agricultural land for solar plants. The following discussion compares the water use of a parabolic trough plant and the product value (electricity vs. crops) to the surrounding community.

During 2001, 522,000 acres of land were used for growing crops in the Imperial Valley irrigation district. An addition 278,000 acres of land was undeveloped. A 100 MW solar plant uses approximately 500 to 1000 acres depending on whether the solar field is oversized for use with thermal energy storage. Approximately 1% of the undeveloped land would be sufficient for approximately 2 GWe of solar capacity.

The primary crop in the Imperial Valley Irrigation District is alfalfa. On average, alfalfa uses 5.5 acre-feet per year per acre of crop land. A parabolic trough plant with wet cooling uses 1.3 acre-foot/year per acre of solar field land use. Water use from a solar plant is approximately one quarter that of alfalfa. In addition, the imperial valley water district charges industrial customers 5 times the agriculture rate, so a solar power plant would generate more revenues for the water district.

One acre of alfalfa crop land generates 7.2 tons of alfalfa per acre per year. The gross revenue for alfalfa farming is approximately $600-900/year/acre. Gross income (before expenses) from a 100MWe solar power plant (at 10¢/kWh) is approximately $42,000/year/acre. Operation and maintenance expenses are approximately $9000/acre/year. Most of this O&M cost is for labor or local goods and services.

Solar plants use less water than most agriculture in the Imperial Valley and can bring in more revenues to the local community and offer more and higher paying jobs.

Advantages to Central Station Solar

Parabolic trough solar thermal power plants, like other renewable energy sources, offer environmental advantages when compared with conventional fossil-fuel energy sources. More important, however, they embody several unique and very important characteristics that make this technology particularly valuable and an underutilized renewable resource with compelling attributes. These advantages include the following:

Technical, Power Quality, and Cost Benefits

- Huge resource potential in Imperial Valley region (>100GWe)
- Excellent siting potential, close to key SDG&E transmission corridors
- Able to achieve high summer on-peak capacity factor from solar energy alone
- Power can be firmed up by hybridizing with natural gas or possibly bio waste fired auxiliary boiler
- Summer on-peak generation can also be firmed up by adding thermal energy storage to the plant
- Thermal storage can also allow the plant to be designed with a larger solar field to increase plant annual capacity factor and to help solar meet winter evening peak and summer evening mid-peak generation from solar energy.
- Good power quality
- Offset natural gas use for peaking plants and mitigate price volatility
- Low emissions from solar power generation with peak output on sunny summer days when air pollution is a concern from other power generation sources
- Significant opportunity for emission reductions and credits are possible with large-scale implementation
- 150 MWe of trough power plants are under development in Nevada and Spain
- Significant available land and at reasonable cost
- Likely the lowest cost large-scale solar option available

Strategic Value

- Fuel diversity
- Supply and cost stability – 30 year fuel supply
- Local fuel supply – money not sent out of state for fuel
- Regional generation source – does not require long-distance transmission of power
- Large-scale solar projects can have a noticeable impact on energy supply
- Potential for rapid deployment – conventional materials, no major factories

- Potential for export of green power to other regions in the state
- Zero CO2 generation
- Strong U.S. Southwest and international pressure to accelerate commercial introduction and growth

Economic Benefit to Community

- Economic impact (jobs) on tax base
- Added high-value jobs in rural areas
- Construction & O&M jobs
- Local material purchases and supplies

Disadvantages to Central Station Solar

There are also drawbacks to solar thermal power plants that need to be taken into consideration.

- Although trough power plants are operating commercially and well, other CSP technologies are in earlier stages of prototype commercial systems. The CSP industry is relatively immature; for troughs three international companies are ready to supply solar steam systems but as yet these firms have not actually constructed new plants. All have substantial expertise with regard to staff and technical data from the SEGS development and operation.
- The thermodynamic cycles of steam or combined-cycle plants require significant cooling to reject heat. The least expensive and most efficient cooling systems are based on water-cooling. In a desert site, water can be scarce which leads to a need for air-cooling. Although trough plants can utilize air-cooling, performance and cost both suffer in the process.
- The heat transfer fluid is considered a hazardous waste in California. Bioremediation techniques have been developed that allow on-site clean up of soils contaminated by spilled fluid, eliminating the need for transporting any hazardous waste off site for disposal.
- Finally, the cost is currently above the market price referent. It is important to note that this technology is capital-intensive and currently shows high electricity costs. To be competitive, these plants require long-term financing and, ideally, opportunities with a low cost of money. Because of capital needs, the tax burden is also high relative to fossil plants. Additional incentives are needed to make this technology directly cost competitive with fossil fuel alternatives.

Recommendations

- SDG&E should work with the CPUC to define the market price referent methodology as it applies to solar power plants, including the proxy technology, cost and performance parameters, and the natural gas price for calculations to be based on.
- SDG&E should implement long-term (30-year) power purchase agreements that incentivize solar technologies that provide high summer on-peak capacity factors.
    - Solar plants should receive full capacity for achieving 80% on-peak.
    - A bonus capacity payment for achieving for exceeding 80% on-peak capacity would encourage plants to be designed to achieve closer to 100% on-peak capacity.
    - A bonus solar energy payment could be paid for the last 20% of solar generation on an annual basis. This would assure that plants were maintained to keep solar output at design levels.
- SDG&E should support expansion of federal and state incentives too improve the economics of near-term solar plants. The type of incentives requested would depend

on whether SDG&E values solar energy, solar capacity, or both. Clearly any federal incentives reduce the amount of state incentives that would be required. New incentives should allow utilities to use them.

  - Incentives should be implemented for an extended period (5 years or more)
  - Because of the time value of money, incentives that can be taken upfront (like the ITC), are more effective dollar for dollar at reducing the cost of power.
  - The power purchase agreement can provide the performance incentives necessary to make sure that the plant continues to perform.
  - State or Federal incentives could take the form of tax credits that are transferred to the utility purchasing power.

- SDG&E should consider developing a solar power park as a utility owned project to help improve the economics.
  - Local municipal ownership could help to reduce the cost of power by reducing taxes and the cost of capital.
  - Innovative public/private project structures should be considered to determine the most attractive approach for developing a large project.
- Larger systems are more cost competitive.
  - Plants of 100 to 200MWe are feasible and much more cost effective than smaller plants.
  - Plants may also be able to be built in a power park arrangement, multiple plants built sequentially at the same location, to help reduce costs.
- Given the low cost of water for industrial users in the Imperial Valley, wet cooling is clearly preferred to dry cooling.
- The North American Development Bank may be able to provide low cost debt for a portion of any project within 100km of either side of the Mexican/U.S. border. This could help improve the economics of any project located in the Imperial Valley or other regions along the border.

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