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# Advances in Parabolic Trough Solar Power Technology

*Parabolic trough solar technology is the most proven and lowest cost large-scale solar power technology available today, primarily because of the nine large commercial-scale solar power plants that are operating in the California Mojave Desert. These plants, developed by Luz International Limited and referred to as Solar Electric Generating Systems (SEGS), range in size from 14–80 MW and represent 354 MW of installed electric generating capacity. More than 2,000,000 m$^2$ of parabolic trough collector technology has been operating daily for up to 18 years, and as the year 2001 ended, these plants had accumulated 127 years of operational experience. The Luz collector technology has demonstrated its ability to operate in a commercial power plant environment like no other solar technology in the world. Although no new plants have been built since 1990, significant advancements 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. This paper reviews the current state of the art of parabolic trough solar power technology and describes the R&D efforts that are in progress to enhance this technology. The paper also shows how the economics of future parabolic trough solar power plants are expected to improve.* [DOI: 10.1115/1.1467922]

## Introduction

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 optional thermal storage and/or fossil-fired backup systems [1,2]. The collector field is made up of a large field of single-axis-tracking parabolic trough solar collectors. The solar field is modular in nature and comprises many parallel rows of solar collectors, normally aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola. 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 (HTF) is heated up as high as 393°C as it circulates through the receiver and returns to a series of heat exchangers (HX) in the power block, where the fluid is used to generate high-pressure superheated steam (100 bar, 371°C). 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 feed-water pumps to be transformed back into steam. Mechanical-draft wet cooling towers supply cooling to the condenser. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field. The existing parabolic trough plants have been designed to use solar energy as the primary energy source to produce electricity. Given sufficient solar input, the plants can operate at full-rated power using solar energy alone. During summer months, the plants typically operate for 10–12 hr/day on solar energy at full-rated electric output. To enable these plants to achieve rated electric output during overcast or nighttime periods, the plants have been designed as hybrid solar/fossil plants; that is, a backup fossil-fired capability can be used to supplement the solar output during periods of low solar radiation. In addition, thermal storage can be integrated into the plant design to allow solar energy to be stored and dispatched when power is required. Figure 1 shows a process flow schematic for a typical large-scale parabolic trough solar power plant.

**Background.** Parabolic trough collectors capable of generating temperatures greater than 260°C were initially developed for industrial process heat (IPH) applications. Several parabolic trough developers sold IPH systems in the 1970s and 1980s, but generally found three barriers to successfully marketing their technologies. First, a relatively high marketing and engineering effort was required, even for small projects. Second, most potential industrial customers had cumbersome decision-making processes, which often resulted in a negative decision after considerable effort had already been expended. Third, the rate of return for IPH projects did not always meet industry criteria. In 1983, Southern California Edison (SCE) signed an agreement with Luz International Limited to purchase power from the Solar Electric Generating System (SEGS) I and II plants. Later, with the advent of the California Standard Offer power purchase contracts for qualifying

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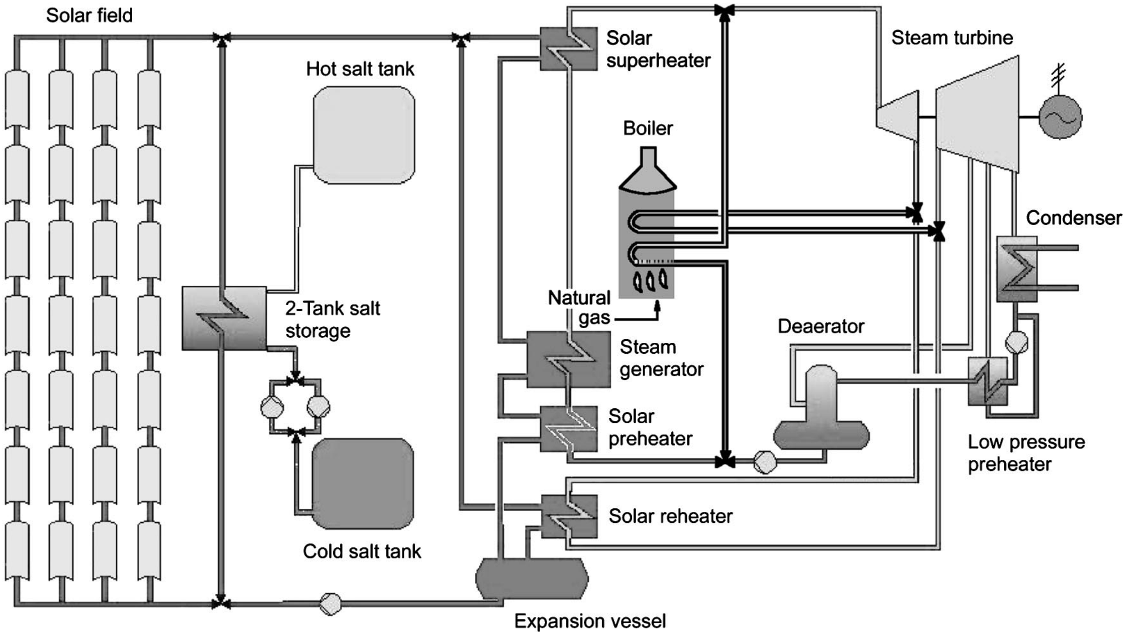


**Fig. 1 Process flow schematic of large-scale parabolic trough solar power plant (Flabeg Solar International)**

facilities under the U.S. Federal Public Utility Regulatory Policy Act (PURPA), Luz was able to sign a number of standard offer contracts with SCE that led to the development of the SEGS III through SEGS IX projects. Initially, PURPA limited the plants to 30 MW in size; this limit was later raised to 80 MW. In total, nine plants were built, representing 354 MW of combined capacity. Table 1 shows the characteristics of the nine SEGS plants that Luz built.

In 1991, Luz filed for bankruptcy when it was unable to secure construction financing for its tenth plant (SEGS X). Although many factors contributed to the demise of Luz, the basic problem was that the cost of the technology was too high to compete in the power market with declining energy costs and incentives. Lotker [3] 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 its 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 continue to operate today in that form. Figure 2 shows the five 30-MW SEGS plants located 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.

Since the demise of Luz, a number of events and R&D efforts have helped resurrect interest in parabolic trough technology. In 1992, Solel Solar Systems Ltd. purchased Luz manufacturing assets, providing a source for the Luz collector technology and key collector components. In the same year, a five-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 Co.) 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. In 1996, the DIrect Solar Steam (DISS) project was initiated at the Plataforma Solar de Almería (PSA) to test parabolic trough collectors that generate steam directly in the solar field. Although comprising only a few collectors, the DISS project was large enough to demonstrate the revived industrial capacity and the potential for substantial technological advances [5].

In 1996, the Global Environment Facility (GEF) approved $49

**Table 1 Characteristics of SEGS I through IX [1]**

| SEGS Plant | First Year of Operation | Net Output ($MW_e$) | Solar Field Outlet Temperature (°C) | Solar Field Area ($m^2$) | Solar/Fossil Turbine Efficiency (%) | Annual Output (MWh) | Dispatchability Provided by |
|---|---|---|---|---|---|---|---|
| I | 1985 | 13.8 | 307 | 82,960 | 31.5/NA | 30,100 | 3 hours— thermal storage Gas-fired superheater |
| II | 1986 | 30 | 316 | 190,338 | 29.4/37.3 | 80,500 | Gas-fired boiler |
| III/IV | 1987 | 30 | 349 | 230,300 | 30.6/37.4 | 92,780 | Gas-fired boiler |
| V | 1988 | 30 | 349 | 250,500 | 30.6/37.4 | 91,820 | Gas-fired boiler |
| VI | 1989 | 30 | 390 | 188,000 | 37.5/39.5 | 90,850 | Gas-fired boiler |
| VII | 1989 | 30 | 390 | 194,280 | 37.5/39.5 | 92,646 | Gas-fired boiler |
| VIII | 1990 | 80 | 390 | 464,340 | 37.6/37.6 | 252,750 | Gas-fired HTF heater |
| IX | 1991 | 80 | 390 | 483,960 | 37.6/37.6 | 256,125 | Gas-fired HTF heater |

**Fig. 2 SEGS III–SEGS VII solar plants at Kramer Junction, CA. The large fields with rows of parabolic trough collectors are readily apparent. The five 30-MWe power plants can be observed near the center of each solar field.**

million (USD) grant for a parabolic trough project in Rajasthan, India. Subsequently, after an in-depth study to evaluate the future cost reduction potential of parabolic trough technology [6], the GEF approved three additional $50 million grants for parabolic trough type technologies in Morocco, Egypt, and Mexico. In addition, interest in concentrating solar power plants is building in Europe because of rising fuel prices and the carbon dioxide ($CO_2$) mitigation concerns that stemmed from world climate conferences held in the last few years. Opportunities in southern European countries such as Spain, Italy [7], and Greece are driving much of the interest. Recently, energy shortages and price volatility in the western United States have also helped to boost commercial interest in the technology.

In 1998, an international workshop on parabolic trough technology led to the development of a parabolic trough technology roadmap [8]. The roadmap identified technology development necessary to reduce cost or improve reliability and performance of parabolic trough technology. The U.S. Department of Energy (DOE) and others have subsequently used this roadmap to help guide 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.

## Solar Collector Technology

This paper specifically refers to parabolic trough collectors for concentrating sunlight. This type of concentrator has a cylindrical shape, with its parabolic curvature described by the formula $Z = x^2/4f$. The distance $f$ represents the position of the focal point of the parabola, essentially the distance of the focal line of the parabola from its vertex. The area formed by the trough-shaped parabola is covered with reflector material to concentrate the solar radiation in the focal line. To do so, the symmetry plane (optical axis) of the parabola has to be directed toward the incoming light from the sun. In other words, such systems have to track with the sun on a single axis to perform. Figure 3 shows an example of a parabolic trough collector and illustrates how the direct beam component of sunlight reflects back to the receiver located at the focus of the parabolic mirrors.

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. All these components are in continuous development, aiming at further cost reductions to enhance market opportunities.

**Support Structure.** The Luz LS-3 collector was the final concentrator design used at the newest SEGS plants (SEGS VII–IX). A variation of the LS-3, which allows the collector to be tilted a few degrees, is used for the direct-steam generation test at the PSA. Although the operational experience of the LS-3 collector has been excellent (high tracking availability), the thermal perfor-

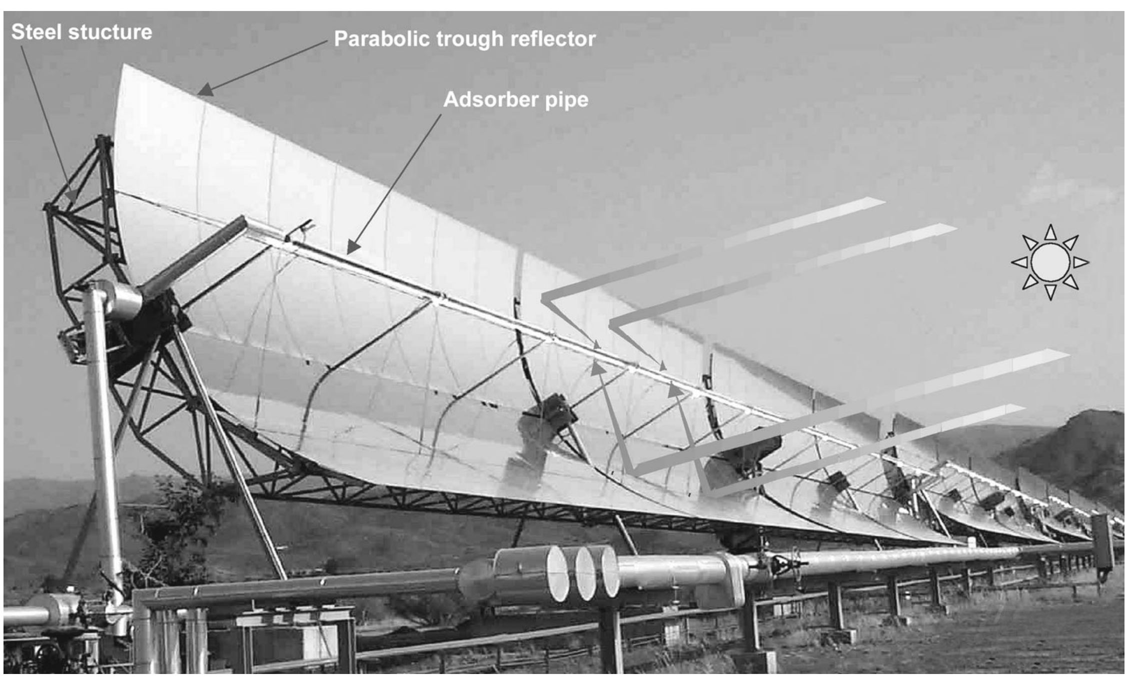


**Fig. 3 Parabolic trough collector (source: PSA)**

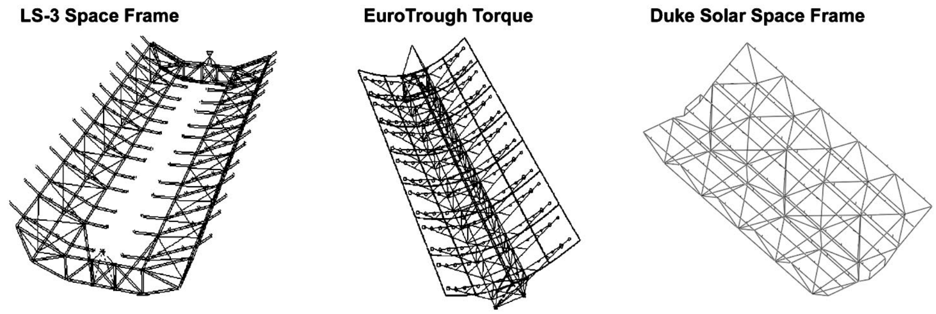


**Fig. 4 LS-3 space frame, EuroTrough torque-box, and Duke Solar Space Frame concentrator designs. (source: EuroTrough and Duke Solar)**

mance and the maintainability (alignment) of the collector has not been equal to the earlier LS-2 design. Luz changed from the LS-2 to the LS-3 design to reduce the collector cost for large field deployments. It is unknown, even by Luz, if the expected capital cost benefit of the LS-3 design over the LS-2 was ever realized. Operational experience from the SEGS plants shows that any cost benefit that may have existed has been clearly offset by performance and maintainability issues associated with the LS-3. Building on the experience and lessons learned by the SEGS plants, several new parabolic trough collector designs are under development as described below.

*EuroTrough.* A consortium of European companies and research laboratories (Inabensa, Fichtner Solar, Flabeg Solar, SBP, Iberdrola, Ciemat DLR, Solel, CRES), known as EuroTrough has completed the development and testing on a next-generation trough concentrator [9]. The consortium has set forth a torque box concentrator concept that is eliminating many of the problems associated with the LS-2 and LS-3 collectors during fabrication and operation. The torque box design combines the torsional stiffness and alignment benefits of the LS-2 torque tube design with the reduced cost of an LS-3 like truss design. Wind-load analysis and finite element modeling identified the design, which is composed of a rectangular torque box with mirror support arms, as the most promising concept (Fig. 4). The rotational axis is in the center of gravity, a few millimeters above the torque box. The torque-box design has less deformation of the collector structure, which can result from dead weight and wind loading, than the LS-3 design. This reduces torsion and bending of the structure during operation and leads to increased optical performance. The stiffer design allows the extension of the collector length from 100 meters to 150 meters. This decreases the total number of required drives for a collector field as well as the number of interconnecting pipes and will reduce total collector cost and thermal losses. The central element of the EuroTrough design is a 12-m-long steel space-frame structure with a square cross-section that holds the support arms for the parabolic mirror facets of 5.8-m aperture width. The box is constructed with only four different steel parts, which has simplified manufacturing processes and reduced costs for on-site assembly and erection. In addition, transportation requirements have been optimized for maximum packing. The design uses mirror supports that use the glass facets as static structural elements, but at the same time reduce the forces onto the glass sheets by a factor of three. This design should experience less glass breakage during high wind conditions. As a result of an improved design of the drive pylon, the SCA can be mounted on an inclined site (3%), which can decrease site preparation costs.

Concentrator accuracy is achieved by combining prefabrication with on-site jig mounting. Most of the structural parts are produced with steel construction tolerances. One of the design objectives was to reduce the weight of the apparatus compared to that of the LS-3 collector structure. The steel structure now weighs about 14% less than the available design of the LS-3 collector.

These improvements—reducing the variety of parts, lessening the weight of the structure, and using more compact transport—are assumed to result in cost reductions in on the order of another 10%. For the total collector installation, series production costs below 175 $USD/m^2$ of aperture area are anticipated.

PSA has successfully tested a prototype collector in Spain (Fig. 5). The collector is set up in the east–west direction for improved testing. Because of budget limitations, only half a collector (drive pylon with collector elements to one side only) has been installed. The tracking controller, developed at PSA, uses a sun vector calculation to determine the collector position [10]. The test program for the prototype includes thermal performance tests with synthetic oil up to 390°C. Further tests focus on optical and mechanical evaluation of the collector. A photogrammetry technique is used to evaluate the precision of the concentrator structure [11] and to verify the optical performance. The test results have shown that the EuroTrough concentrator is an improvement of about 3% in performance over the LS-3 collector. Several project developers and consortia have selected the EuroTrough collector as their solar field technology.

*Duke Solar.* Duke Solar, in Raleigh, North Carolina, has formulated an advanced-generation trough concentrator design that uses an all-aluminum space frame (DS1) [12]. This design is patterned after the size and operational characteristics of the LS-2 collector. The new design is superior to the LS-2 in terms of structural properties, weight, manufacturing simplicity, corrosion resistance, manufactured cost, and installation ease. Finite element models of the LS-2 and the new space frame design were developed to assess both structures accurately. The structural models show that the new space frame closely matches the LS-2 in both torsional stiffness as well as beam stiffness. Detailed and compre-

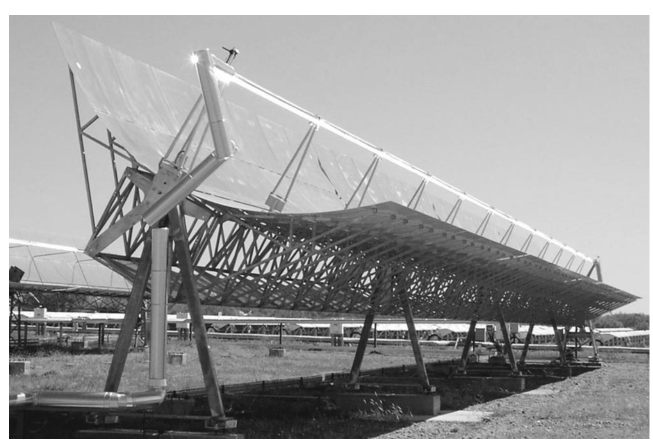

**Fig. 5 The EuroTrough collector prototype under test at PSA (Source: PSA)**

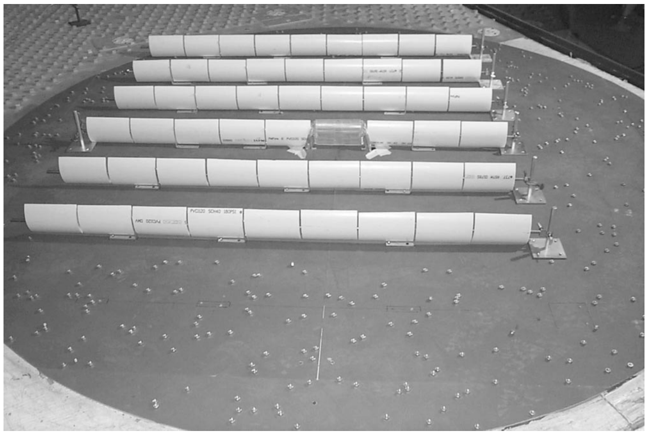

**Fig. 6 Wind tunnel testing of parabolic trough collectors to achieve optimized structural design (source: Duke Solar)**

hensive wind tunnel testing has augmented the structural analysis (Fig. 6) [13]. The space frame's structural design is based on achieving the high resistance to wind loads (i.e., high bending stiffness and torsional stiffness) that the LS-2 has demonstrated, which will yield excellent performance in the field.

In addition, the design emphasizes simplicity of fabrication and a minimum number of required parts. All the struts used in the space frame are 2-in. rectangular extruded aluminum tubes, and the structure is easy to assemble. The space frame is composed of 137 aluminum struts, arranged in a three-dimensional truss-like pattern (Fig. 4) and connected by a field-installed hub system. A single drilled hole through each end of each strut is used to connect the struts to the hubs. These interconnected struts, then, create the space frame. In terms of weight, this space frame design has a significant advantage since it is about half the weight of the LS-2 structure. A lightweight structure is superior in terms of shipping, handling during manufacture, and field installation. The space frame also has greater corrosion resistance because it is made entirely of aluminum. The space frame is engineered to accept the standard silvered-glass mirrors that have demonstrated excellent corrosion resistance and reliability in the operating LS-2 collector systems. Although the installed costs of the Duke Solar parabolic trough will be lower than those of the LS-2 collector, the same high level of performance will be sustained. Currently, further design optimization is under way, which will soon be followed by the fabrication and testing of a prototype collector. In addition to testing the collector's thermal performance, detailed optical characterization is planned.

*Industrial Solar Technology (IST).* IST has produced parabolic trough collectors that have been used primarily for lower temperature process heat applications. As part of NREL's USA Trough Program, IST is upgrading its collector to perform more efficiently at higher temperatures and to reduce the cost. The company is converting its concentrator from aluminum to a galvanized steel structure; replacing the aluminized polymeric reflector with a thin, silvered-glass reflector; updating the collector's local and field computer controllers to use off-the-shelf hardware; and upgrading the solar-selective absorber coating on the receiver to improve thermal performance and durability at higher temperatures [14]. The change to steel and thin glass reflector is estimated to reduce current system costs by 15%, and to increase performance by 12%. These improvements are likely to result in a 25% drop in the cost of delivered energy. Table 2 highlights the key elements of these new designs along with the original Luz concentrator designs.

**Reflector Development.** The Luz LS-3 parabolic trough concentrator uses a glass mirror reflector supported by the truss system that provides its structural integrity. The glass mirrors, manufactured by Flabeg Solar International (FSI; formerly Pilkington Solar International, Köln, Germany), are made from a low-iron 4-mm float glass with a solar-weighted transmittance of 98%. The glass is heated on accurate parabolic molds in special ovens to obtain the parabolic shape. The mirrors are silvered on the back and then covered with several protective coatings. Ceramic pads used for mounting the mirrors to the collector structure are attached with a special adhesive. The high mirror quality allows

**Table 2 Data on one-axis parabolic trough collectors**

| Collector | Structure | Aperture width m | Focal length m | Length per element $m^2$ | Length per collector m | Mirror Area per drive $m^2$ | Receiver Diameter m | Geometric concentration sun | Mirror Type | Drive | Module Weight per m2 kg | peak optical efficiency % | Reference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LS-1 | Torque tube | 2.55 | 0.94 | 6.3 | 50.2 | 128 | 0.04 | 61:1 | Silvered low-iron float glass | Gear | n/a | 71 | SEGS I+II |
| LS-2 | Torque tube | 5 | 1.49 | 8 | 49 | 235 | 0.07 | 71:1 | Silvered low-iron float glass | Gear | 29 | 76 | SEGS II–VII |
| LS-3 | V-truss framework | 5.76 | 1.71 | 12 | 99 | 545 | 0.07 | 82:1 | Silvered low-iron float glass | Hydraulic | 33 | 80 | SEGS V–IX |
| New IST | Space frame | 2.3 | 0.76 | 6.1 | 49 | 424 | 0.04 | 50:1 | Silvered thin glass | Jack screw | 24 | 78 | IST [14] |
| Euro-Trough | Square truss torque box | 5.76 | 1.71 | 12 | 150 | 817 | 0.07 | 82:1 | Silvered low-iron float glass | Hydraulic | 29 | 80 | PSA [9] |
| Duke Solar | Aluminum space frame | 5 | 1.49 | 8 | 49–65 | 235–313 | 0.07 | 71:1 | Silvered low-iron float glass | Hydraulic or gear | 24 | 80 (projected) | Duke DS1 [12] |

Note: Module weight is for the tracking parabolic concentrator unit and includes the structure, mirrors, receiver, and receiver supports. The pylons, drive system, and flexible interconnections are not accounted for in the module weight.

more than 98.5% of the reflected rays to be incident on the linear receiver. When new, the mirrors have a solar-weighted reflectance of 93.5%. The operational experience with the mirrors has been very good. After more than 15 years of service, the mirrors can still be cleaned to their as-new reflectivity. With the latest design, mirror failures have been infrequent. Still, failures have been experienced on the windward side of the field where there is no wind protection. In addition to presenting a safety hazard, mirror failures can cause damage to the receiver tube and can actually cause other mirrors to break. FSI is working with the operator of the SEGS VIII and IX plants to test a stronger (thicker) mirror for high wind perimeter locations. The company is also developing new mounting hardware to help transfer wind loads to the steel structure [10]. New collector designs will also likely move the pad-mounting locations for glass mirrors closer to the corners of the mirrors to further reduce loads on the mirrors.

*Structural Facets.* Structural facets offer a potentially stronger mirror facet that can be integrated into the concentrator design and used as part of the concentrator structure. The goal is to create a stronger and lower cost reflector facet that can lower the overall cost of the concentrator. Current focus is primarily on developing replacement facets for the existing SEGS plants. IST developed a replacement facet for the Luz concentrator, and KJC Operating Company purchased several thousand to use in high wind locations. These facets used aluminum skins with a cardboard honeycomb core and 3M's EPC-305+ polymeric reflector. Initially these facets performed well, but later a water-soluble adhesive used to glue the skins and the honeycomb core reacted with the honeycomb core, causing corrosion of the aluminum skins and eventual blistering in the reflective material. The blistering significantly reduced the specular reflectance of the polymeric reflector. KJC also reported some change in the mirror curvature over time. Paneltec Corporation also developed a replacement facet for the Luz concentrator [15]. It uses steel skins with an aluminum honeycomb core material and thin glass for the reflector. The Paneltec facet used a vacuum-bagging manufacturing process that allowed a number of facets to be manufactured at the same time, all stacked on the same mandrel. Several hundred of the Paneltec facets were manufactured and are currently being field tested at the SEGS plants. Although they have only been in field service for a couple years, they appear to be maintaining their optical accuracy and reflective quality. The primary problem with the Paneltec facet is its initial cost. The manufacturing process is labor intensive, largely because of the thin glass mirrors used for the reflective surface. The availability of an alternative reflector that would allow the manufacturing process to be simplified could dramatically improve the economics of the Paneltec facet. A number of other structural facets concepts are also being developed, including facets made from foam, laminated glass/fiberglass, thermoformable polymeric substrates, and various metal structure concepts. These, however, are all at early stages of development field experience with the concepts is insufficient.

*Advanced Reflector Development.* Alternatives to glass mirror reflectors have been in service and under development for more than 15 years. NREL has been working on polymeric reflectors since the 1980s. Polymeric reflectors are attractive because of their light weight, curvability, and low cost. However, until recently none of these materials has demonstrated cost, performance, and lifetime characteristics required for commercial trough development. Jorgensen updates the status of the most promising alternative reflectors in [16].

- Thin glass mirrors are as durable as a glass reflector and relatively lightweight in comparison to thick glass. However, the mirrors are more fragile, which increases handling costs and breakage losses. Thin glass can have initial solar-weighted reflectance of 93–96% and costs in the range of $15–40/m^2. The solar experience with thin glass reflectors is mixed. Some corrosion has been experienced, but this is likely a result of the adhesive selected and the substrate to which the mirrors are attached. To address this, new thin glass experimental samples were recently developed and are being tested under controlled conditions.
- 3M is developing a nonmetallic, thin-film reflector that uses a multilayer *Radiant Film* technology. The technology employs alternating co-extruded polymer layers of differing refractive indices to create a reflector without the need for a metal reflective layer. The alternating polymer layers enable multiple Fresnel reflections at the interfaces of the respective layers, which results in a very high overall reflection over the visible wavelength bandwidth. This technology has the potential for very high reflectance (~99%) over more broadband wavelength regions with no metal reflective layer that can corrode. Spectral characteristics can be tailored to the particular application. Current samples under evaluation have exhibited high reflectance in a narrow band but have had a problem with ultraviolet (UV) durability. 3M plans to develop an improved solar reflector with improved UV screening layers and a top layer hardcoat to improve outdoor durability.
- ReflecTech and NREL are jointly developing a laminate reflector material that uses a commercial silvered-polymer reflector base material with a UV-screening film laminated to it to result in outdoor durability. The initial solar-weighted specular reflectance is ~93%, and the cost is projected to be $10–15/m^2, depending on volume. The reflective film, which possesses excellent mechanical stability, is not subject to the *tunneling* problems that have plagued other reflective film constructions. NREL has completed water-immersion tests that have shown no signs of delamination, tunneling, or degradation. Initial prototype accelerated-exposure test results have also been promising, although additional work on material production is needed. The material would also benefit from a hardcoat for improved washability.
- Luz Industries Israel created a front surface mirror (FSM) that consists of a polymeric substrate with a metal or dielectric adhesion layer; a silver reflective layer; and a proprietary, dense, protective top hardcoat. The reflector has excellent initial reflectance. Durability testing of the Luz prototype demonstrated outstanding durability with solar-weighted reflectance >95% for more than five years of accelerated-exposure testing and >90% for more than six years. The accelerated-exposure testing subjects the prototype to at least three times (3×) the normal exposure rate and to an elevated temperature as high as 60°C, making the test equivalent to nearly 20 years of outdoor exposure. Although Solel Solar Systems LTD has supplied new samples for evaluation, the company has not yet demonstrated the same performance as seen on the initial Luz samples.
- SAIC of McLean, Virginia, and NREL have been developing a material called *Super Thin Glass*. This is also a front surface mirror concept with a hardcoat protective layer. The material uses an ion-beam-assisted deposition (IBAD) process to deposit the very hard (cleanable), dense (protective) alumina topcoat. The material can be produced on a roll-coater, with either a polymeric or a steel substrate. NREL has developed two additional hardcoats for use with front surface mirrors; they have demonstrated excellent optical characteristics, durability, and cost reduction potential as well.
- Alanod of Köln, Germany has developed a front surface aluminized reflector that uses a polished aluminum substrate, an enhanced aluminum reflective layer, and a protective oxidized alumina topcoat. These reflectors have inadequate durability in industrial environments. A product with a polymeric overcoat to protect the alumina layer has improved durability. Samples have survived >3 years outdoor exposure testing in Köln. A number of structural facets have been con-

**Table 3 Alternative reflector technologies [17]**

| | Solar Weighted Reflectivity (%) | Cost ($\$/m^2$) | Durability | Abradable during Washing | Issues |
|---|---|---|---|---|---|
| Flabeg Thick Glass | 94 | 40 | Very good | Yes | Cost, breakage |
| Thin Glass | 93–96 | 15–40 | Very good | Yes | Handling, breakage |
| All-Polymeric | 99 | 10 | Poor | No | UV protective coating needed with hard coat |
| ReflecTech Laminate | >93 | 10–15 | In full-scale testing | No | Hard coat and improved production |
| Solel FSM | >95 | NA | NA | Yes | Solel product durability currently unknown |
| SAIC Super Thin Glass | >95 | 10 | Good | Yes | Manufacturing scaleup |
| Alanod | ~90 | <20 | Good | No | Reflectivity |

structed with this material. The product is commercially available from Alanod at a cost of $<\$20/m^2$ and an initial solar-weighted reflectance of ~90%.

Table 3 summarizes the characteristics of the reflector technology alternatives. At this point, thick glass will likely remain the preferred approach for large-scale parabolic trough plants, although alternative reflector technologies may be more important in the future as more advanced trough concentrator designs are developed.

**Receiver Development.** The parabolic trough linear receiver, also called 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 outside diameter (O.D.) stainless steel tube with a cermet solar-selective absorber surface, surrounded by an antireflective(AR) evacuated glass tube with an 115-mm O.D. The HCE incorporates conventional glass-to-metal seals and metal bellows to achieve the necessary vacuum-tight enclosure and to accommodate for thermal expansion difference between the steel tubing and the glass envelope. The vacuum enclosure serves primarily to significantly reduce heat losses at high operating temperatures and to protect the solar-selective absorber surface from oxidation. The vacuum in the HCE, which must be at or below the Knudsen gas conduction range to mitigate convection losses within the annulus, is typically maintained at about 0.0001 mm Hg (0.013 Pa). The multilayer cermet coating is sputtered onto the steel tube to result in excellent selective optical properties with high solar absorptance of direct beam solar radiation and a low thermal emissivity at the operating temperature to reduce thermal reradiation. The outer glass cylinder has an AR coating on both surfaces to reduce Fresnel reflective losses from the glass surfaces, thus maximizing the solar transmittance. Getters, which are metallic compounds 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. A diagram of an HCE is shown in Fig. 7.

Although highly efficient, the original Luz receiver tubes experienced high failure rates (approximately 4–5% per year). Failures included vacuum loss, glass envelope breakage, and degradation of the selective coating, which typically occurs with the presence of oxygen after the vacuum is lost or the glass envelope breaks. Any such failure also has a significant impact of the receiver's thermal performance [17]. At the SEGS plants, replacing damaged receiver tubes typically has a payback of 1–5 years, representing an important O&M cost. Several factors, including improper installation and operational practices, contributed to the initial high failure rates at the existing SEGS plants. Although these types of failures have been markedly reduced in recent years, they are still important. The failure of the glass-to-metal seal is the primary ongoing issue, which is believed to be caused by concentrated flux hitting the seal. SNL has used finite element modeling to quantify the stresses developed in the glass-to-metal seal area [18]. These finite element analysis (FEA) results indicate that the current glass-to-metal seal must be protected from concentrated solar flux (from either direct or redirect rays) to reduce the stress levels below the glass fracture threshold. Work is under way to modify the glass-to-metal seal configuration to effectively reduce the stresses generated during concentrated flux. Better protection of the glass-to-metal seal from the concentrated flux should significantly reduce HCE failures. KJC Operating Company and Solel have developed improved coverings to protect the glass-to-metal seal, and seal failures are decreasing [19].

*Solel Universal Vacuum (UVAC).* At the outset, Luz Industries Israel manufactured the receiver for all the SEGS plant projects. Solel Solar Systems then acquired the Luz receiver manufacturing line and currently makes spare parts for the SEGS facilities. Solel has continued to develop and improve the receiver selective coating and is working to improve receiver tube reliability. The company's improved design is called the UVAC HCE. The UVAC receiver, which has an improved solar-selective absorber coating, also incorporates an internal reflective shield that protects the inside of the glass-to-metal seal during low-sun-angle operating conditions. The UVAC also uses a different cermet coating composition that eliminates the coating oxidization failures that often resulted when the original Luz cermet tubes lost vacuum. Table 4 shows the receiver selective coating properties of the Luz cermet and the Solel UVAC receiver tubes as measured by SNL and independently by Solel [20]. KJC Operating Company (the operator of SEGS III–VII) is currently testing Solel UVAC receiver tubes to evaluate both their performance and reliability. Preliminary test data show a significant performance improvement of the UVAC tubes compared with the original Luz receiver tubes (Fig. 8) [21]. Although it is too early to know if the receiver's reliability

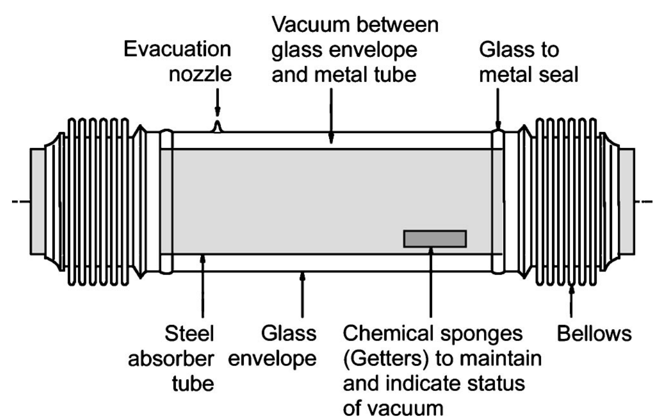


**Fig. 7 Heat collection element (HCE) (source: Flabeg Solar International)**

**Table 4 HCE thermal characteristics**

| Receiver | Luz Cermet | Solel UVAC | Solel UVAC |
|---|---|---|---|
| Data source | SNL [18] | SNL [19] | SOLEL [21] |
| Envelope solar transmittance | 0.95 | 0.96 | NA |
| Coating solar absorptance | 0.915 | 0.95–0.96 | >0.96 |
| Coating thermal emittance | 0.14 @350°C | 0.15 @400°C | 0.091 @400°C |

has been significantly improved, increased understanding of the issue is likely to significantly reduce failures at future plants. The UVAC design represents a significant advancement for future parabolic trough plants. The cost of the UVAC is expected to be similar to previous Solel receivers.

*Alternative Receiver Designs.* The Solel UVAC receiver is an obvious choice for new plants, but for replacement parts at existing plants, a lower cost and lower performance option is often preferable to the high-performance Solel design. A number of low-cost retrofit designs have been developed for use at the SEGS plants. Sunray Energy, the operator of the SEGS I and II plants (which operate at lower temperatures than the later SEGS plants) has developed retrofit receiver designs with support from SNL [22]. These designs allow receivers to be fabricated using recycled stainless steel tubing and also to be repaired in place in the field. Both receiver designs utilize a thin painted layer of Pyromark™ Series 2500 black paint for the absorber coating and on-site manufacturing processes for either full-length fused glass envelopes or full-length split glass envelopes. The field repair returns approximately 80% of the performance of a new UVAC receiver at about 20% of the cost.

Another low-cost retrofit design is being implemented at Florida Power and Light (FPL) Energy–Harper Lake, the owner and operator of SEGS VIII and IX, is implementing another low-cost retrofit design. For these plants, which operate at higher temperatures, a receiver retrofit program rehabilitates receiver tubes that have the glass broken off but still have a good cermet solar-selective coating. These receivers are refurbished using a special sol-gel overcoat [developed by SNL and Energy Laboratories, Inc. (ELI)], which provides an oxidation barrier for the cermet that would normally degrade in air at operating temperatures. These tubes are then reglazed and reinstalled in the field. These refurbished HCEs return approximately 90% of the performance of a new UVAC receiver at about 30% of the cost [22].

An additional low-cost HCE option will soon be available. It utilizes a new, proprietary solar-selective absorber coating, known

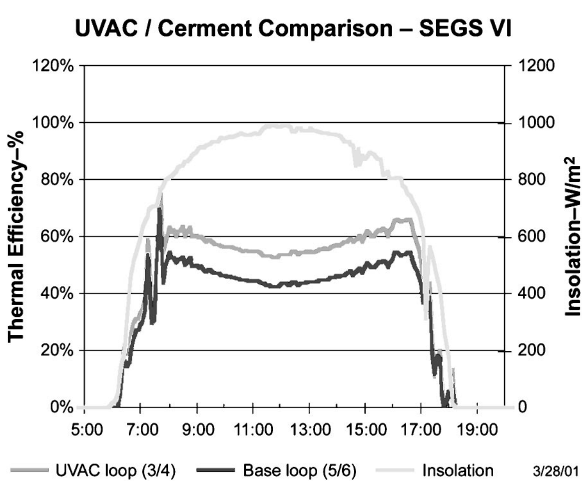


**Fig. 8 Solel UVAC receiver test at SEGS VI (source: KJC Operating Company)**

as Black Crystal, developed by ELI and SNL [22]. This coating incorporates sol-gel overcoat(s) to mitigate oxidation at operating temperatures for an air-in-annulus receiver—the initial HCE design. This coating's optical properties are a solar absorptance of ~0.94 and thermal emittance of ~0.25 at 300°C. On stainless steel substrates, the coating exhibits thermal stability at temperatures <375°C. It can be applied to new stainless steel tubing or to recycled stainless steel tubing (with seriously degraded cermet), which is available from the SEGS plants. The recycled tubing can be straightened and must be prepared for the deposition of the Black Crystal absorber material. The coated steel tube can be reglazed with a conventional or AR-coated glass envelope. These new HCEs will be field tested to evaluate the long-term performance and durability of the design.

Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas (CIEMAT) has developed a new sol-gel selective coating, which is stable in air at 450°C. Solgel is an inexpensive technique that can be used to produce coatings with special optical properties. The new selective coating, which is suitable for commercial parabolic trough collectors, has an absorptivity of 0.9 and an emissivity of 0.14 at 400°C [22,23]. The industrial process to manufacture commercial absorber pipes using this new selective coating is being developed. Although the optical efficiency of this new absorber is lower than that of the Solel UVAC, it will be much cheaper. CIEMAT has also developed a sol-gel AR film to increase receiver glass transmittance up to 97%. This AR film has a good mechanical durability and is suitable for the glass envelope of absorber pipes for parabolic troughs.

SNL is also investigating new concepts in receiver design that could result in substantially lower cost receivers with nearly the same high performance as the Solel receivers. One of the SNL designs uses a high-temperature gasketing approach for connecting the glass envelope to the metal absorber, in place of the glass-to-metal seal. To reduce convective heat losses, the receiver annulus between the glass and metal tube would be pressurized with an inert gas. Although preliminary data look promising, extensive long-term field-testing is required on any new receiver design to evaluate and validate the reliability and also to assess whether the receiver's life-cycle costs have been lowered.

Double-layer cermet coatings have been proposed to improve the thermo/optical properties of current receiver technology [8,24]. The double-layer cermet should be cheaper to produce than the current graded coatings. Further testing is required to determine whether these advantages will prove out in actual commercial production.

*Receiver Secondary Reflectors.* A recent study was conducted to evaluate the potential benefits of non-imaging secondary reflectors for an LS-2 collector [25]. The investigation included a parametric analysis to gain a better understanding of the potential optical advantages—including a small improvement in the optical intercept of a parabolic trough receiver (about 1%), and reduced receiver thermal loss (about 4%)—that the design offers. Overall, the net performance advantage of the secondary reflector was calculated to be about 2%; that is, the entire trough collector field would have a 2% greater annual thermal energy output. The effect of rim angle of the primary concentrator was also investigated and the optical advantage was found to be virtually the same (from 70 to 80 deg, with a slightly smaller advantage for a 90-deg rim angle). Finally, a method of manufacturing the secondary reflector was formulated, and cost analysis of the reflector was completed. The cost estimates indicate that the cost of a secondary reflector can add less than $60 to the cost of a 4-m-long evacuated receiver. At this price, the addition of a secondary reflector offers only a modest performance enhancement to parabolic trough collectors. However, the design does achieve other indirect benefits, such as better flux uniformity around the absorber tube and an increased tolerance of the parabolic trough collectors to optical errors. For parabolic trough designs that can benefit from these other at-

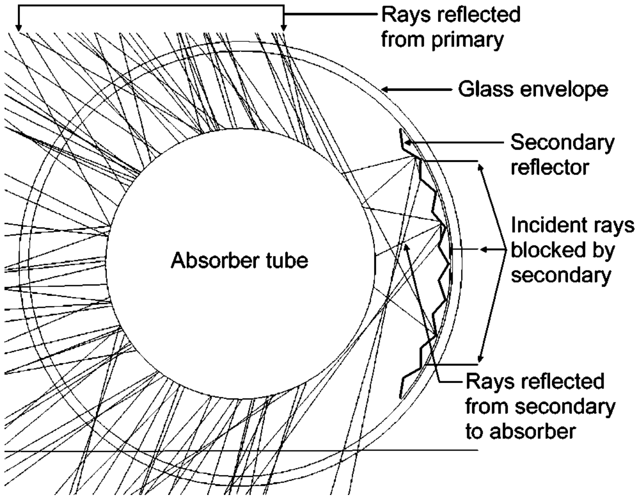


**Fig. 9 Trough receiver with secondary reflector (source: Duke Solar)**

tributes, using a secondary reflector can be valuable. Figure 9 shows the output of ray tracing software modeling a parabolic trough receiver with a secondary concentrator.

For next-generation parabolic trough plants, the Solel UVAC will probably be the receiver design of choice. However, the design and coating developments currently under way are likely to result in further improvements in trough system cost and performance.

## Heat Transfer Fluids and Thermal Storage

Parabolic trough solar collectors utilize an HTF that flows through the receiver to collect the solar thermal energy and transport it to the power block. The type of HTF used determines the operational temperature range of the solar field and thus the maximum power cycle efficiency that can be obtained. One of the potential advantages of parabolic trough technologies is the ability to store solar thermal energy for use during non-solar periods. Thermal storage also allows the solar field to be oversized to increase the plant's annual capacity factor. In good solar climates, trough plants without thermal storage can produce an annual capacity factor of approximately 25%. Adding thermal storage allows the plant capacity factor to be increased to 50% or more.

**Heat Transfer Fluid.** The selection of the type of HTF will also affect the type of thermal storage technologies that can be used in the plant. Table 5 shows the available HTF options. The choice of the fluid is directly linked to the required application temperature and further options like storage.

Biphenyl-diphenyl-oxide, known by trade names Therminol VP-1 [26] and Dowtherm A [27], in use at the latest SEGS plants, has shown excellent stability. Although it is flammable, safety and environmental protection requirements can be satisfied with reasonable effort. The primary limitations are the temperature range, the cost for the oil itself, and the need for heat exchange equipment to transfer thermal energy to the power cycle. In addition, because the fluid has a high vapor pressure, it cannot be easily used to store thermal energy for later dispatch.

**Thermal Storage.** The first SEGS plant used mineral oil HTF and included three hours of thermal storage [28]. The plant used a two-tank system; one tank held the cold oil and a separate tank held the hot oil once it had been heated. This helped the plant dispatch its electric generation to meet the utility peak loads during the summer afternoons and winter evenings. The system worked well until 1999 when it was destroyed by a fire caused by a failure in its tank blanketing system. The mineral oil HTF is very flammable and could not be used at the later, more efficient SEGS plants that operate at higher solar field temperatures. A mineral oil thermal storage system was also used at the Solar One steam central receiver demonstration power plant [28]. This system used a single-tank thermocline storage system with rock/sand filler. The storage system at Solar One worked well, although thermodynamically it was not well suited for integration with the central receiver steam conditions used at Solar One. The storage system also experienced fires related to the use of the Caloria storage fluid.

No thermal storage systems have been demonstrated commercially for the higher solar field operating temperatures (approximately 400°C) required for more efficient steam cycles in the later SEGS plants. For these plants, the two-tank storage system used at SEGS I is not feasible because cost of the synthetic HTF is higher. In addition, the high vapor pressure of biphenyl-diphenyl-oxide would require pressurized storage vessels. A recent study by FSI [29] reviewed thermal storage options for high-temperature parabolic trough plants and identified a number of promising thermal storage options that could be used for higher temperature parabolic trough plants.

*Concrete.* A thermal storage system that uses concrete as the storage medium has been proposed. This system would use a heat transfer fluid in the solar field and pass it through an array of pipes imbedded in the concrete to transfer the thermal energy to and from the concrete. Limited prototype testing has been done on the concrete-steel thermal storage concept [30]. From 1991 to 1994, two concrete storage modules were evaluated at the storage test facility at the Center for Solar Energy and Hydrogen Research

**Table 5 Heat transfer fluids with application in solar parabolic trough fields**

| Fluid | Application temperature (°C) | Reference | Properties |
|---|---|---|---|
| Synthetic oil, e.g., VP-1 Biphenyl-diphenyloxide | 13–395 | [2] | Relatively high application temperature, flammable |
| Mineral oil, e.g., Caloria | −10–300 | [2] | Relatively inexpensive, flammable |
| Water, pressurized, +glycol | −25–>100 | | Only low-temperature IPH applications |
| Water/steam | 0–>500 | [5] | High receiver pressure required, thick-wall tubing |
| Silicon oil | −40–400 | [9] | Odorless, nontoxic, expensive, flammable |
| Nitrate salt, e.g., HITEC XL | 220–500 | [32] | High freezing temperature, high thermal stability, corrosive |
| Ionic liquids, e.g., $C_8mimPF_6$ | −75–416 | [34] | Organic methyl-imidazole salts, good thermal properties, very costly, no mass product |
| Air | −183–>500 | | Low energy density, only special IPH applications |

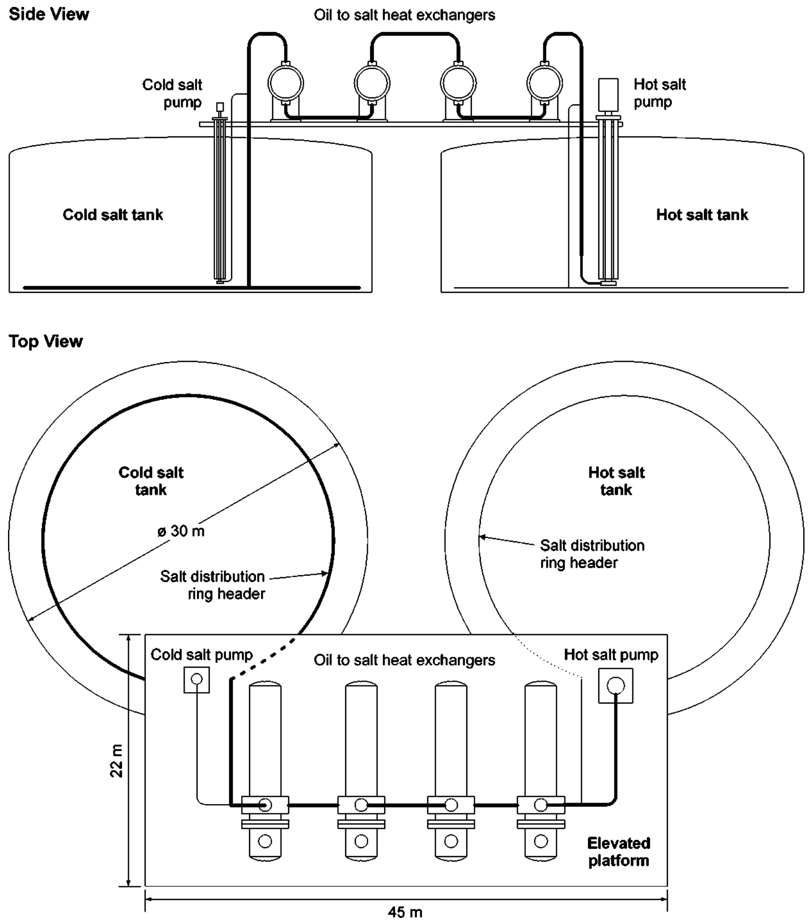


**Fig. 10 Two-Tank indirect trough thermal storage design (Source: Nexant)**

(ZSW) in Stuttgart, Germany. The test results confirmed the theoretical performance predictions. The cost for the concrete thermal storage was estimated to be $40/kWh$_t$ in 1994 for a 200-MWh system. Storage costs for commercial-scale systems are expected to be on the order of $26/kWh$_t$. The highest uncertainty is the long-term stability of the concrete material itself after thousands of charging cycles.

*Indirect Two-Tank Molten-Salt.* A near-term thermal storage option for parabolic trough technology uses biphenyl-diphenyl-oxide HTF in the solar field and then passes it through a heat exchanger to heat molten salt in the thermal storage system [3]. The molten salt is the same *solar salt* used at the Solar Two pilot demonstration plant [30], a binary mixture of 60% sodium nitrate ($NaNO_3$), and 40% potassium nitrate ($KNO_3$) salt. When the power cycle is dispatched, the salt flow is reversed through the HTF/salt heat exchanger to reheat the HTF. Otherwise, this system is a conventional SEGS type HTF steam generator system. Although this system has not been demonstrated commercially, a number of pilot-scale demonstrations, especially Solar Two, have shown that this thermal storage system is feasible and has relatively low risk. Nexant (formerly Bechtel) has conducted a detailed design and safety analysis of the indirect molten-salt thermal storage system [3]. The Nexant study considered a thermal storage design that would provide two hours of full load energy to the turbine of an 80-MW SEGS plant (see Fig. 10). Although solar salt has a relatively high freezing point (~225°C), the salt is kept in a relatively compact area and is easily protected by heat tracing and systems that drain back to the storage tanks when not in use. By examining the experience at Solar Two, the Nexant study concluded that this thermal storage concept has low technological risk. The study also found that the system had a specific cost of $40/kWh$_t$. Storage systems with more hours of storage relative to the turbine capacity would have lower specific costs, because the cost of the heat exchanger dominates the cost of the system.

*Thermocline Storage.* One option for reducing the thermal storage cost for trough plants is to use a thermocline storage system. Recent studies and field-testing validated the operation of a molten-salt thermocline storage system [31]. The thermocline uses a single tank that is only marginally larger than one of the tanks in the two-tank system. A low-cost filler material, which is used to pack the single storage tank, acts as the primary thermal storage medium. The filler displaces the majority of the salt in the two-tank system. In a recent test of a thermocline storage system at SNL's National Solar Thermal Test Facility, the filler material, quartzite, and silica sand replaced approximately two-thirds of the salt that would be needed for a two-tank system. With the hot and cold fluid in a single tank, the thermocline storage system relies on thermal buoyancy to maintain thermal stratification. The thermocline is the region of the tank between the two temperature resources. In the SNL test, with a 60°C temperature difference between the hot and cold fluids, the thermocline occupied between 1 and 2 m of the tank height. For this reason, the thermocline storage system seems to be best suited for applications with a relatively small temperature difference between the hot and cold fluids. The SNL testing showed that the thermocline maintained its integrity over a three-day no-operation period. The study shows a cost comparison of two-tank and thermocline indirect molten-salt thermal storage systems with three hours of thermal storage for an 80-MW plant. The comparison shows that the thermocline system is 35% cheaper than the two-tank storage system.

**Table 6 Costs for 800 $MWh_t$ two-tank and thermocline indirect and direct thermal storage [33]**

| Component | Indirect Storage System | | Direct Storage Systems | |
|---|---|---|---|---|
| | Two-Tank | Thermocline | Two-Tank | Thermocline |
| Solar Field HTF, type | Therminol | Therminol | Hitec XL | Hitec XL |
| Outlet Temperature (C) | 393 | 393 | 450 | 450 |
| Storage Fluid, type | Solar Salt | Solar Salt | Hitec XL | Hitec XL |
| Fluid cost, (k USD) | 11,800 | 3,800 | 14,800 | 3,000 |
| Filler material, type | NA | Quartzite | NA | Quartzite |
| Filler cost, (k USD) | 0 | 2,200 | 0 | 2,300 |
| Tank(s), number | 2 | 1 | 2 | 1 |
| Tank cost, (k USD) | 3,800 | 2,400 | 5,600 | 3,100 |
| Salt-to-oil heat exchanger, (k USD) | 5,500 | 5,500 | 0 | 0 |
| Total, (k USD) | 21,100 | 13,900 | 20,400 | 8,400 |
| Specific cost, (USD/$kWh_t$) | 31 | 20 | 25 | 11 |

*Molten-Salt HTF.* Using a lower temperature molten salt as the HTF in the solar field [32] is another innovative approach that is being pursued. This allows the same fluid to be used in both the solar field and the thermal storage system, eliminating the need for the expensive heat exchangers between the solar field and storage system. In addition, the solar field can be operated to higher outlet temperatures, increasing the power cycle efficiency and further reducing the cost of thermal storage. The primary disadvantage is that the lowest temperature molten salt available at a reasonable cost is Hitec XL, which freezes at approximately 120°C. Because of this, much more care must be taken to make sure that the salt HTF does not freeze in the solar field. The higher outlet temperature also has some negative impacts as well, including higher heat losses from the solar field, concerns about the durability of the selective coating on the trough receivers, and the need for more expensive piping and materials to withstand the increased operating temperatures. Overall, however, initial findings for this concept look encouraging, appearing to offer a significant reduction in the cost of thermal storage, especially when used in a thermocline configuration. Table 6 shows a comparison of direct and indirect thermal storage systems for a 50 MWe trough plant with 800 $MWh_t$ of thermal storage for both two-tank and thermocline configurations. Thermal storage specific costs as low as \$11/$kWh_t$ were calculated for the direct thermocline storage system.

*Organic Molten-Salt HTF.* Work at the University of Alabama and NREL is looking into using a new class of fluids known as organic salts (or ionic liquids) as the HTF and thermal storage media in a parabolic trough plant [33]. Organic salts are similar in many ways to the inorganic salts that have historically been used in solar applications. Their primary advantage is that many organic salts are liquid at room temperatures. In addition, they can be synthesized to have specific properties desirable for a solar application. Optimal thermophysical properties and attributes for a salt HTF are a low freezing point, high thermal stability, low corrosivity in standard materials, good heat transfer and thermal properties, and low cost. Although a number of candidate fluids have already been identified that seem to meet many of the other requirements, the cost is likely to be the key issue for organic salts. The development of organic salts is relatively new, and to date they have only been used industrially in very small quantities. However, because of their attractive environmental character-

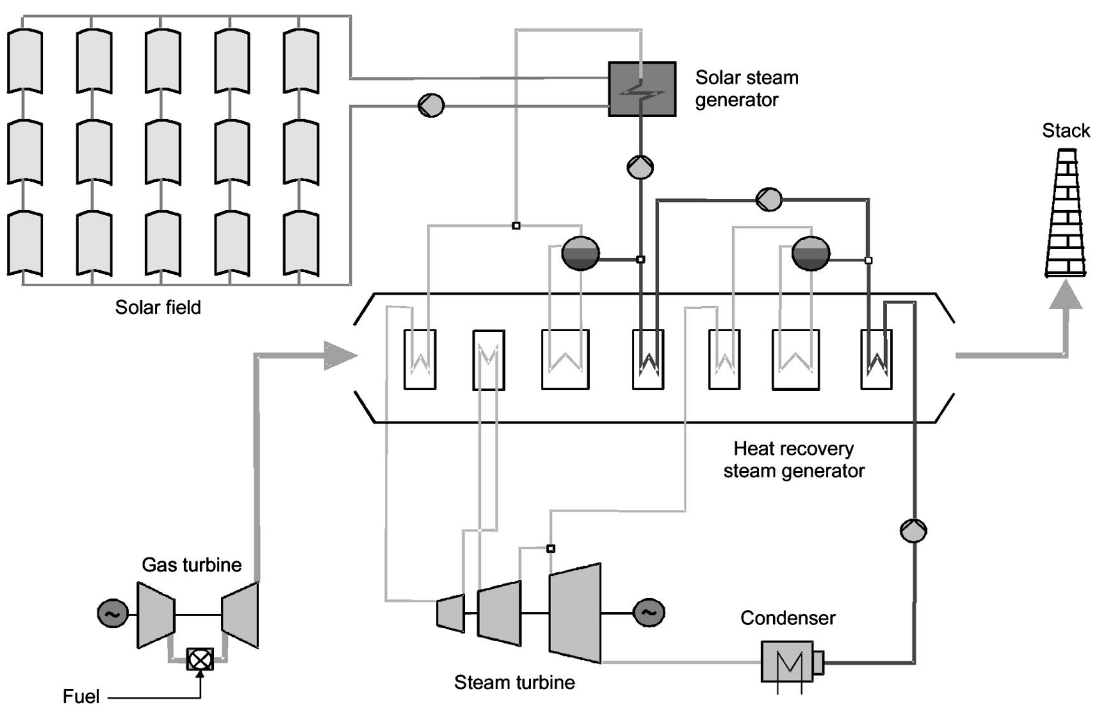


**Fig. 11 Scheme of an ISCCS power plant with a dual-pressure-reheat steam cycle using solar energy to replace latent heat of evaporation in the high-pressure part (source: TIPP)**

istics, organic salts will probably find significant application in large industrial processes as solvents. Increased commercial demand should help to drive the costs down.

The development of a viable and cost-effective thermal storage technology is essential for parabolic trough technology. It now appears that the indirect two-tank molten-salt technology represents a low risk option for near-term trough projects. Several other technologies are currently under development that could dramatically improve the cost and performance of thermal storage for future trough power plants.

## Process Design Developments

All the SEGS plants have utilized a heat transfer fluid in the solar field to collect thermal energy and a train of heat exchangers to generate steam for a conventional Rankine cycle power plant. A number of alternative process concepts are currently under development to reduce cost, improve siting flexibility, or address other market niches.

*Integrated Solar Combined-Cycle System (ISCCS).* The ISCCS integrates solar steam into the Rankine steam bottoming cycle of a combined-cycle power plant. The general concept is to oversize the steam turbine to handle the increased steam capacity. At the high end, steam turbine capacity can be approximately doubled, with solar heat used for steam generation, and gas turbine waste heat used for preheating and superheating steam. Unfortunately, when the solar energy is not available, the steam turbine must run at part load, which reduces efficiency. Doubling the steam turbine capacity would result in a 25% design point solar contribution. Because solar energy is available only about 25% of the time, the annual solar contribution for trough plants without thermal storage would be only about 10% for a base-load combined-cycle plant. Adding thermal storage could double the solar contribution. Studies show [34,35] that the optimum solar contribution is typically less than the maximum; the more the steam turbine is oversized, the greater the off-design impact on the fossil plant when solar is not available. The ISCCS configuration is currently being considered for a number of GEF trough projects. The ISCCS improves the economics of trough solar technology because the incremental cost for increasing the steam turbine size on a combined-cycle plant is substantially lower than that of a stand-alone Rankine cycle power plant. In addition, the solar steam may be converted at a substantially higher efficiency in some cases. A recent study that evaluated an ISCCS configuration for Mexico estimated the incremental solar costs of a 30-MW ISCCS system at below 10¢/kWh [36]. Although the ISCCS configuration offers a potentially lower cost approach for building a parabolic trough power plant, it is not clear if the economic in-

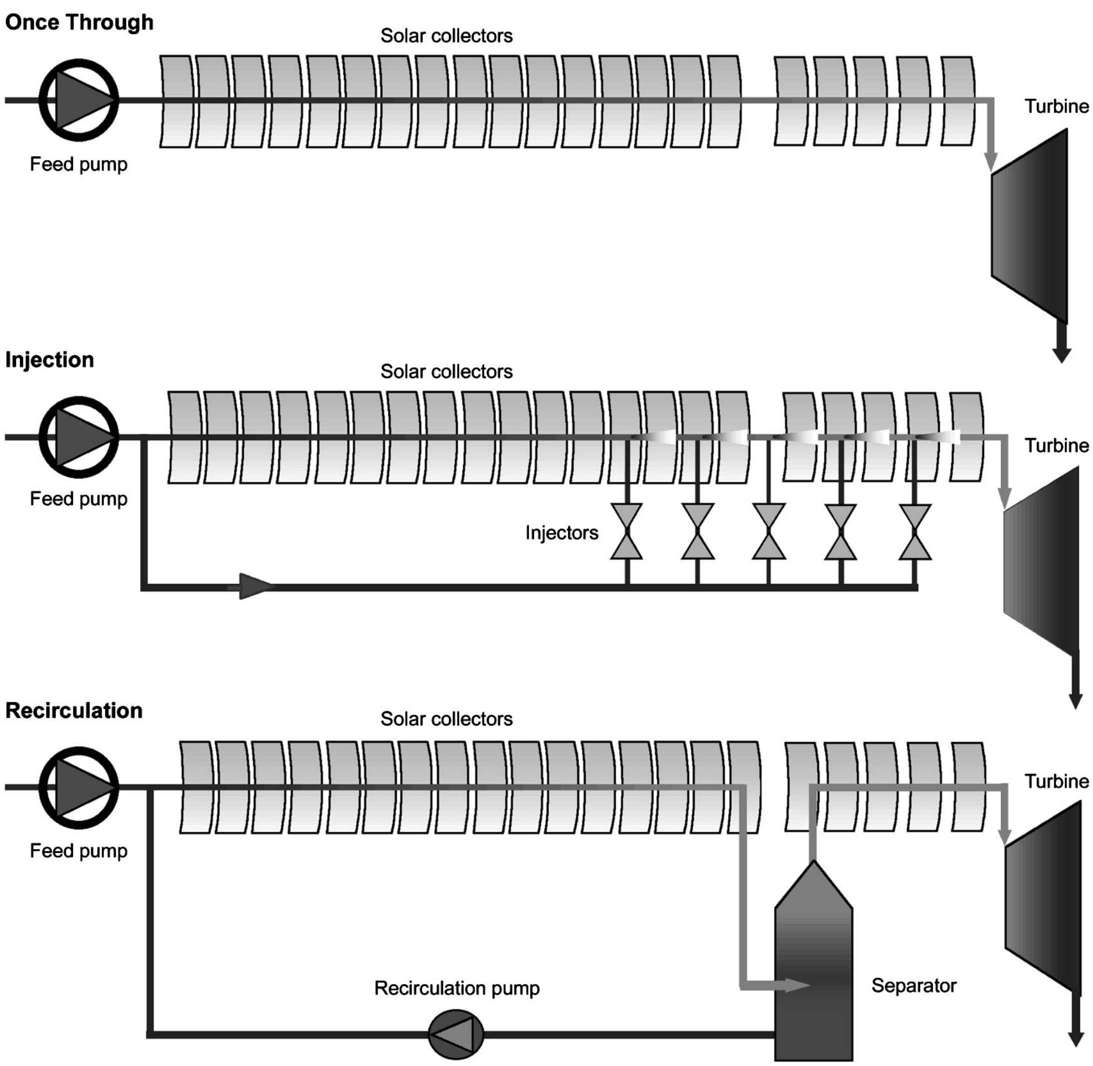


**Fig. 12 The three basic DSG processes: once-through (top), injection (center), and recirculation (bottom) (source: DISS)**

centive is worth the potential risk to the conventional combined-cycle plant. Figure 11 shows the process flow diagram for an ISCCS plant.

*Direct Steam Generation (DSG).* DSG refers to the generation of steam in the collector field, which eliminates the need for an intermediate HTF like Therminol VP-1. Although DSG increases the cost of the solar field piping by increasing the solar field fluid (steam) working pressure to above 100 bar, DSG reduces the overall plant investment cost because it eliminates the HTF steam generation heat exchangers and all the elements associated with the HTF circuit (i.e., fire extinguishing system, oil expansion tank, oil tank blanketing system, etc.). Efficiency is increased by eliminating the heat exchange process between HTF and steam, reducing heat losses through improved heat transfer in the collector, increasing power cycle efficiency through higher operating temperatures and pressures, and through reducing pumping parasitics. One study indicates a 7% increase in annual performance and a 9% reduction in the solar system costs, resulting in an approximate 10% reduction in the solar levelized cost of energy (LEC) [37]. The study was performed for a small trough field in an ISCCS plant, an approximate 10-MW equivalent. The advantages may be greater for larger plants. Trough DSG is currently being successfully tested at the PSA [6,38]. Although it was initially assumed that the solar collectors would need to be tilted at 8 deg above horizontal to maintain the appropriate two-phase flow patterns in the receiver tube, DSG in the receivers of horizontal LS-3 collectors has been successfully proven at the PSA. The DSG technology may be best applied when used only to generate steam; the technology's advantage would be less for plants where solar energy is also used to preheat and superheat the steam. It is too early to tell whether DSG will be preferred to HTF trough plants. The SEGS O&M companies have serious safety and maintenance concerns about having large solar fields of high-pressure steam, but DSG tests performed so far at the PSA are encouraging and 100 bar steam is currently produced with LS-3 troughs without any problem. Current thermal storage concepts will not work for DSG. A phase-change thermal storage may be better adapted for this application. The DSG test in progress at PSA will demonstrate the three basic DSG collector field processes (Fig. 12): once-through, injection, and recirculation. Zarza [6] provides an overview of the testing to date.

*Organic Rankine Cycle (ORC).* Several geothermal companies are currently investigating the integration of geothermal power plant technology with parabolic trough solar technology [39,40]. These systems would use ORCs with air-cooling. Systems under consideration range in size from 100 kWe to 10 MW. ORCs have a number of advantages over steam-Rankine power cycles. ORCs can be much simpler because the working fluid can be condensed at above atmospheric pressures, and a noncondensing regenerator can be used in place of regenerative feed-water heaters. ORC systems operate at lower pressures, reducing the capital cost of components and operational pumping parasitics. Design studies indicate that optimized ORC systems could be more efficient than more complex steam cycles operating at the same solar field outlet temperature. The other advantage to the ORC system is that it reduces water consumption by about 98% compared to conventional SEGS type plants.

NREL analyzed a 1-MW ORC trough plant configuration (Fig. 13) [41]. The general concept is to create a small modular trough plant design that is highly packaged. The ORC technology reduces the need for on-site operations personnel, which helps to reduce the overall cost of electricity from these plants. Small geothermal plants have successfully operated as unattended power plants, and IST has demonstrated reliable unattended operation of trough solar fields. Modular plant designs that can be produced in quantities of 10–20 systems are expected to reduce the ORC power plant cost to about $1/W. With current ORC cycles, electricity costs of about 20¢/kWh appear possible. An ORC optimized for a 300°C operating temperature from a trough solar field should allow a significant increase in the ORC efficiency. In addition, at these temperatures, thermal storage is economically feasible, allowing solar capacity factors of 50% or higher to be

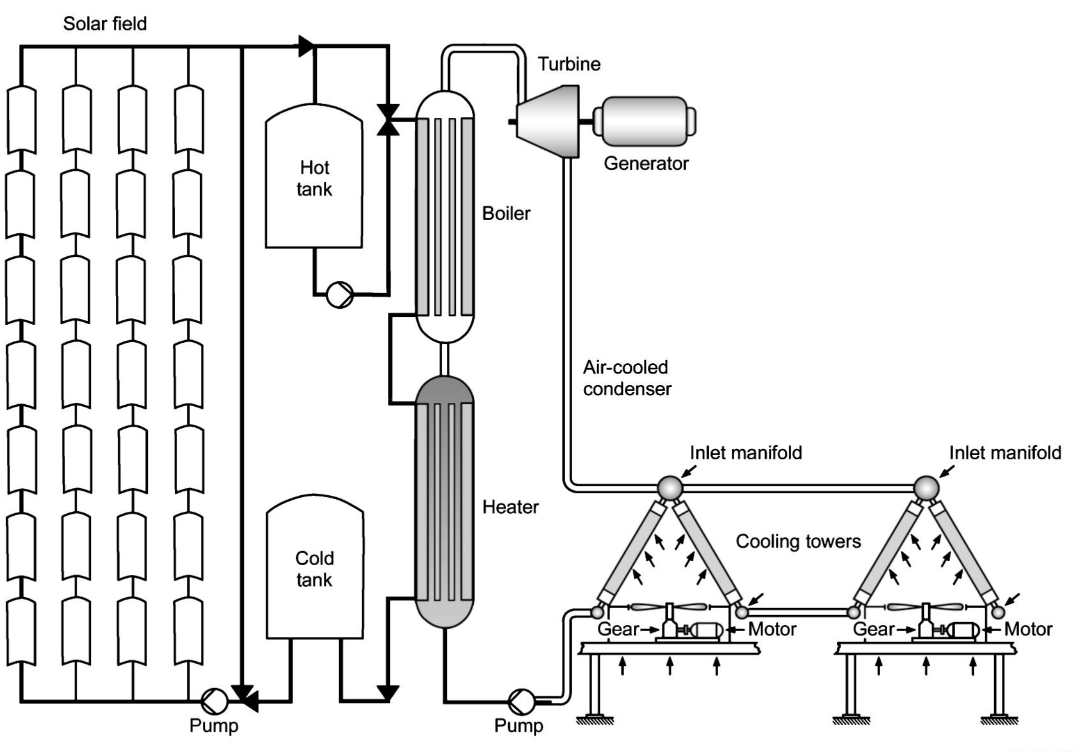


**Fig. 13 Basic organic Rankine cycle (source: NREL)**

**Table 7 Trough power cycle alternatives**

| Plant/Cycle | Solar Field/ Turbine Working Fluid | Solar Field Outlet Temperature (°C) | Turbine Inlet Temperature (°C) | Solar Mode Efficiency (%) | Reference |
|---|---|---|---|---|---|
| SEGS I | Caloria/steam | 307 | 418 | 32[i] | [1] |
| SEGSIII-V | Therminol VP-1/steam | 349 | 327 | 31 | [1] |
| SEGS VIII/IX | Therminol VP-1/steam | 390 | 371 | 38 | [1] |
| SEGS Salt HTF | Hitec XL/steam | 450 | 430 | 40 | [33] |
| DISS | Steam/steam | 550 | 550 | 42 | [6] |
| ISCCS | Therminol VP-1/steam | 390 | 565 | 45[ii] | [35] |
| ORC | Caloria/organic fluid | 307 | 293 | 22 | [42] |

[i]Steam superheated by a natural gas fired superheater,
[ii]Effective solar power cycle efficiency based on increase in electric output resulting from solar thermal input.

achieved. Using these assumptions, solar electricity costs of 10¢–12¢/kWh appear achievable. Integrating these technologies may be attractive for remote or distributed power applications.

Table 7 provides and overview of the most common power cycles under consideration for use with parabolic trough solar technology and typical design point process conditions and efficiencies.

## Operations and Maintenance

Parabolic trough 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. 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. This is a difficult service for both equipment and O&M crews. 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 later plants solved many of these problems, the O&M costs at the SEGS plants were generally higher than Luz expectations.

The KJC Operating Company's O&M cost reduction study [5] addressed many of the problems that were causing high O&M costs. 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,
- Improving 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
- Developing a replacement for flex hoses that uses hard piping and ball joints; resulting in lower replacement costs, improved reliability, and lower pumping parasitics.

A significant focus of the study was the development of improved O&M practices and information systems for better optimization of O&M crews. The key accomplishments included:

- An updated 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/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/MWh at future plants.

## Trough Plant Economics

To understand the future potential of parabolic trough technology, we can compare the cost of two of the existing SEGS plants with the projected cost of two future parabolic trough plants. The 30-MW SEGS VI project and the 80-MW SEGS IX projects are used as reference cases for the existing SEGS plant technology. The first future case represents the technology of a near-term plant based on current parabolic trough technology, which includes advances made and demonstrated over the last 10 years. This case assumes a 100-MW solar-only plant with six hours of thermal storage and an oversized solar field with a solar multiple of 1.8. The second future case represents a more advanced future trough technology based on the expected improvements in cost and performance for the parabolic trough R&D efforts currently in progress. This case assumes a 200-MW solar-only plant with 12 hours of thermal storage and a solar field with a solar multiple of 2.6. Table 8 shows the design, performance, and capital and O&M costs for each of the plants examined.

The solar multiple is merely a mechanism for referencing the thermal delivery of the solar field relative to the design thermal input of the power cycle. A solar multiple of 1.0, for example, means that the solar field under design conditions (we assume 1,000 $W/m^2$, a solar incidence angle of zero, an ambient temperature of 25°C, and wind velocity of 2.5m/s) delivers the design thermal input to the power plant. A solar multiple of 1.8 means that the solar field would deliver 80% more thermal energy than the power plant requires under the specified design solar conditions. Note that the existing SEGS plants have solar multiples of approximately 1.25.

**Table 8 Cost of electricity**

| Case | SEGS VI | SEGS VIII | Near-Term | Advanced |
|---|---|---|---|---|
| Plant size | 30-MW; 5 plants co-located | 80-MW; 5 plants co-located | 100-MW; single plant | 200-MW; 5 plants co-located |
| Solar field | | | | |
| Collector type | LS-2 | LS-3 | LS-2+[vi] | Advanced |
| Solar multiple | 1.25 | 1.25 | 1.8 | 2.6 |
| Collector area ($m^2$) | 188,000 | 464,340 | 800,000 | 2,000,000 |
| Collector cost (USD/$m^2$) | NA | NA | \$222/$m^2$ | \$147/$m^2$ |
| Collector efficiency | | | | |
| Thermal storage | None | None | 4 hours | 12 hours |
| Cost (USD/kWht) | | | 30 | 9 |
| Total capital cost (USD/kWe)[i] | 5676 | 4033 | 3150 | 2535 |
| O&M cost (USD/MWh)[ii] | 29 | 25 | 17 | 6 |
| Annual solar to electric efficiency (%) | 11 | 10 | 13 | 16 |
| Annual capacity factor[iii] (%) | 33 | 28 | 33 | 53 |
| Solar fraction | 0.7 | 0.7 | 1.0 | 1.0 |
| Fuel cost (USD/MWh)[iv] | 10 | 11 | 0 | 0 |
| LEC (USD/MWh)[v] | | | | |
| Luz LEC (1988/2001 USD) | 117/175 | 79/118 | | |
| Actual LEC (2001 USD) | 194 | 164 | | |
| NREL forecast (2001 USD) | | | 101 | 49 |

[i]2001 USD
[ii]O&M costs assume solar field maintained similar to SEGS VI
[iii]Annual capacity factors based on expected plant performance for a solar resource of 2840 kWh/$m^2$ (Kramer Junction, CA) and general O&M assumption
[iv]2.8 USD/kJ (3USD/MMBtu) gas cost, higher heat value, averaged over all generation
[v]LEC based on 6.0% discount rate and 0.5% annual insurance cost.
[vi]An upgraded LS-2 collector is viewed as the lowest risk collector design for a next plant however other collector designs currently under development such as the EuroTrough or DS1 could be used as well.

The capital cost data for the SEGS plants are based on the actual financed project costs [42] adjusted to 2001 USD based on the U.S. Department of Labor's consumer price index. The SEGS plant performance and O&M costs are based on actual plant experience, assuming that the solar fields are maintained in good working condition. Table 8 shows the LEC at 194 USD/MWh at the 30-MW SEGS plant and 164 USD/MWh at the 80-MW SEGS plant (in 2001 USD). Table 8 also shows the Luz cost estimates for these plants, both in 1988 and 2001 USD. The Luz LECs are significantly lower because of the aggressive cost and performance assumptions made in original Luz estimates [4].

Future project cost and performance projections are based on a model NREL developed [43] for evaluating parabolic trough power plant technology. The projections are based on hourly plant performance simulations that have been validated against actual SEGS plant performance data. The capital cost is based on data developed by FSI. Based on its extensive involvement with Luz and subsequent efforts to market trough power plants [2,44,45], FSI developed a detailed cost model. NREL adapted these cost estimates based on the current status of parabolic trough technology for the near-term case, and on reasonable advances in future technology for the advanced case. For the near-term case, we assume the solar technology is an LS-2 type collector updated with the Solel UVAC receiver and ball joints assemblies in place of flex hoses. This case assumes that the thermal storage is based on the Nexant indirect two-tank molten salt thermal storage design. The plant is configured as shown in the process flow diagram in Fig. 1. Table 8 shows the LEC for the near-term trough plant at \$104/MWh.

The advanced case assumes a 33% reduction, from the near-term case, in the cost of the solar equipment. Most of this cost reduction is already expected to result from collector development efforts currently under way [10,13]. This case also assumes further advances in receiver technology. The advanced case also assumes the use of the high-temperature molten-salt HTF and the thermocline thermal storage system [33], which improves the power cycle efficiency and reduces the solar field parasitics. Through competition and power park development, the cost of the power plant and the balance of plant is assumed to decrease by 10% in the future case. Table 8 shows the LEC for the advanced trough plant at 49 USD/MWh.

The future cost cases presented here are based on trough plant configurations using a HTF in a steam Rankine power plant. Other configurations using direct steam generation in the solar field or integrating with a combined-cycle power plant could result in even lower costs than those presented here.

According to a recent study by RDI Consulting (a large coal, natural gas, and electric industry consulting firm) [46], because parabolic trough plants with thermal storage should be able to dispatch power to meet peak power demand in the U.S. Southwest, the value of solar power from these plants should be around \$50–60/kWh. Based on this value of power, future parabolic trough plants should be able to compete directly with conventional fossil-fuel power plants.

## Conclusion

The operating performance of the existing parabolic trough power plants has demonstrated this technology to be robust and an excellent performer in the commercial power industry. And since the last commercial parabolic trough plant was built, substantial technological progress has been realized. Together, these factors mean that the next generation parabolic trough plants are likely to be even more competitive, with enhanced features such as economical thermal storage. In addition, worldwide R&D efforts are likely to continue to drive costs down and improve the performance and capabilities of this renewable energy option. Parabolic trough solar power technology appears to be capable of competing directly with conventional fossil-fuel power plants in mainstream markets in the relatively near term. Given that parabolic trough technology utilizes standard industrial manufacturing processes, materials, and power cycle equipment, the technology is poised for rapid deployment should the need emerge for a low-cost solar power option.

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## Nomenclature

| | | |
|---|---|---|
| AR | = | Antireflective |
| CIEMAT | = | Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas, Almería, Spain |
| DISS | = | Direct solar steam |
| DOE | = | U.S. Department of Energy |
| DSG | = | Direct (solar) steam generation |
| ELI | = | Energy Laboratories, Inc.—Jacksonville, FL |
| FEA | = | Finite element analysis |
| FPL | = | Florida Power and Light—Harper Lake, CA |
| FSI | = | Flabeg Solar International, Köln, Germany |
| FSM | = | Front surface Mirror |
| GEF | = | Global Environment Facility of the World Bank |
| HCE | = | Heat collection element (receiver tube) |
| HTF | = | Heat transfer fluid |
| HX | = | Heat exchangers |
| IBAD | = | Ion-beam-assisted deposition |
| IPH | = | Industrial process heat |
| ISCCS | = | Integrated solar combined-cycle system |
| IST | = | Industrial Solar Technology |
| LEC | = | Levelized cost of energy |
| LS-3 | = | Luz System Three Parabolic Trough Collector |
| NREL | = | National Renewable Energy Laboratory |
| O.D. | = | Outside diameter |
| O&M | = | Operations and maintenance |
| ORC | = | Organic Rankine cycle |
| PSA | = | Plataforma Solar de Almería, Spain |
| PURPA | = | U.S. Federal Public Utility Regulatory Policy Act |
| SCA | = | Solar collector assembly |
| SCE | = | Southern California Edison Electric Utility |
| SEGS | = | Solar Electric Generating System |
| SNL | = | Sandia National Laboratories |
| UV | = | Ultraviolet |
| UVAC | = | Universal Vacuum (SOLEL HCE Receiver—most recent version) |
| ZSW | = | Center for Solar Energy and Hydrogen Research, Stuttgart, Germany |

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