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Solar Thermal Power Generation: The Solar Tower, Progress Toward Commercialization

INTRODUCTION

In August of 1984 a utility assumed independent operation of Solar One.[1] This ten Megawatt electric (MW_e) solar powered thermal generating plant (Figure 1) is now operated by Southern California Edison as an integrated part of its plant mix. During a three-year period, detailed records will be kept to determine operating cost, availability, capacity factor, reliability, performance, failure modes, degradation rates, and other needed data. It is expected that this information will convince a majority of those in the utilities, regulatory agencies, and investment community who are yet uncertain about this promising alternative energy source that its commercial application is feasible and worthwhile.

With sufficient confidence in the technology and with a growing economy expanding energy requirements, there is every reason to expect that several new solar power tower plants in the 30-100 MW_e "commercial" scale will be ordered to meet increased intermediate load requirements in the rapidly growing sunbelt. Modest federal support to lower the investment cost of the first few "demonstration" facilities can lead directly to significant cost reductions in future plants, making them competitive immediately with gas or oil-fired units and eventually with coal-fired plants designed to meet environmental constraints. The cost economies will follow from the reduction of engineering and development costs for the majority of the plant, and from cost reductions associated with mass production and "learning" or "experience" curves for the heliostats and receiver panels, the solar collecting component of the facility.

THE PILOT PLANT SOLAR ONE

Solar One is a pilot plant of the central receiver or solar power tower concept for the effective collection and efficient use of solar energy. In this concept the solar energy is intercepted by thousands of heliostats in

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[1] Solomon, *SoCal Edison Puts Solar One on Line Fulltime, Abandons Plans for Solar 100 Project*, The Energy Daily, Aug. 29, 1984 , at 1-2, col. 1-2.

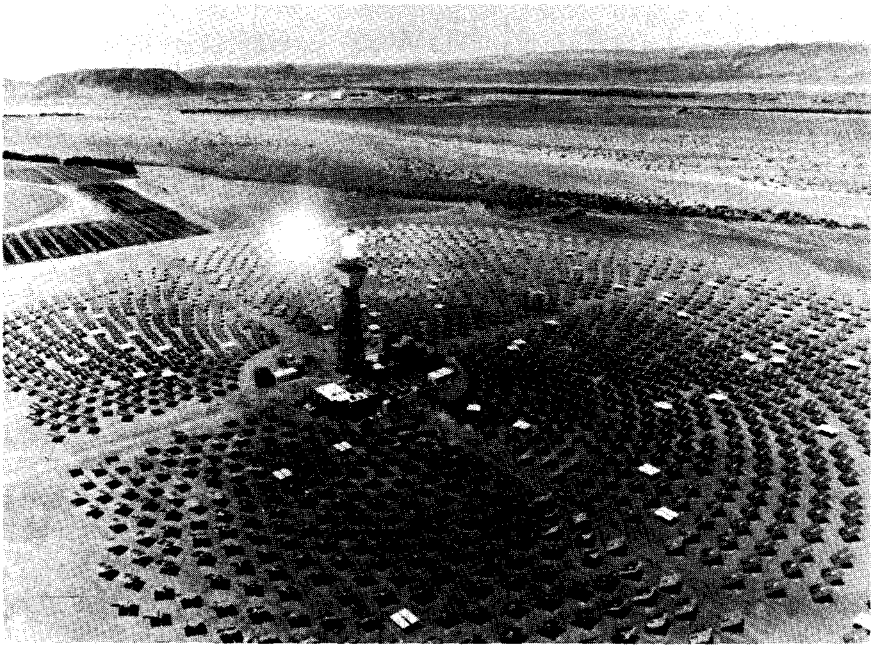

FIGURE 1. Solar One, ten miles east of Barstow, California. This pilot plant for a commercial scale central receiver contains 78,000 ft^2 of glass mirrors, all reflecting sunlight to the receiver centered 260 feet above the field. (Photo by McDonnell Douglas)

the collector subsystem.[2] Each heliostat is simply a large steerable mirror which is aimed by computer control to continuously reflect the direct beam sunlight toward a central receiver. In this way, the difficult task of transporting 100 to 1000 MegaWatts of thermal power (MW_t) to a central point to power the conversion equipment is handled by optical transmission through the atmosphere, at no cost and at an efficiency of about 95%. Superimposition of the thousands of reflected "images" on the elevated central receiver produces a concentration of 200 to 2000 suns on the receiver surface of the receiver subsystem. Here 95% of the incident sunlight is absorbed on the blackened absorber surface of the receiver tubes. Depending on receiver design, concentration, and temperature, 80% to 90% of the absorbed energy is transmitted through the thin tube

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[2] Hildebrandt, Haas, Jenkins & Colaco, *Large-Scale Concentration and Conversion of Solar Energy,* 53 EARTH SCI. TRANSACTIONS OF AM. GEOPHYS. UNION 684 (1972); *see also* Hildebrandt & Vant-Hull, *A Tower Top Focus Solar Energy Collector,* AM. SOC. MECH. ENG. PUB. #73WA/Sol-7 (1973); Hildebrandt & Vant-Hull, *id.*, in 96 MECH. ENG. 23-27 (1974); and Vant-Hull & Hildebrandt, *Solar Thermal Power System Based on Optical Transmission,* 18 SOLAR ENERGY 31-39 (1976).

walls (2-4 millimeters (mm)) into a heat transfer fluid flowing through the tubes.

The design of the receiver and balance of the plant interact strongly with the choice of heat transfer fluid used in the heat transport subsystem. In Solar One, for example, the heat transfer fluid is water/steam. Feedwater pumps pump ultra pure water through 1680 parallel thirteen mm outside diameter (OD) Incoloy tubes (8 mm inside diameter (ID)) at about 100 Bars pressure. The tubes are heated by 45 MW of 300 times concentrated sunlight. In a single pass through the 12.5 meter (m) long heated tubes, the water is converted to 500°Centigrade (C) superheated steam which is manifolded into a 30 centimeter (cm) diameter downcomer and brought to the ground. Here it may be used directly to drive the 10 MW_e turbine generator, or it may be desuperheated and used to charge a thermal storage unit.

The impracticality of storing steam is overcome in Solar One by using the steam directed to the thermal storage subsystem to heat a heat-transfer oil to 310°C. This oil is then circulated through a tank enclosing a 20 m diameter by 15 m high bed of sand (1 mm D) and pebbles (1 cm D) in which a thermocline is maintained. Once the pebble bed is fully charged, the flow of oil can be reversed, and over three hours of derated operation at 7 MW_e can be achieved by directing the 275°C steam produced from storage to the intermediate pressure admission port of the turbine of the electric power generation subsystem.

Clearly, with two energy "sources" (receiver and charged storage unit) and two energy "sinks" (discharged storage unit or turbine) a multitude of operating modes is possible. During the 1982-84 test period of Solar One, the previously developed operating procedure for each of the seven significant modes was checked out in detail as were all of the significant transition modes, e.g., 'receiver to turbine and storage' transition to 'receiver, and storage to turbine.'[3]

To facilitate the planned transfer of the plant to utility operation in August 1984, Southern California Edison employees had been operating the plant under the direction of the solar facility design team during the entire two year test phase. As a result, they became exceedingly familiar not only with the standard operating modes, but also with the wide range of peculiar operating conditions that comprise the test phase. In addition, since May, 1983, the utility operators have been operating the plant on weekends without any test engineers present. In fact, unburdened by test requirements, weekend performance has been exceedingly good, auguring well for the success of the 1984-86 "operating" phase.

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[3] Raetz & Riedesel, *Power Plant Startup and Initial Operation of Solar One*, 6 PROGRESS IN SOLAR ENERGY 507-12 (1983).

During the two years of the test program, more than 8,000 MW hours of solar electricity were generated by Solar One and every one of the test goals was exceeded. This feat was accomplished in spite of notoriously bad weather during this period, and regardless of a presumably unrelated reduction in direct beam intensity of 20% due to worldwide atmospheric contamination caused by the eruption of the Mexican volcano, El Chicon, just immediately at the start of the test period.

Solar One has been a highly successful project.[4] It was constructed essentially on schedule and on budget and has exceeded all its design goals during the test period. It has even been characterized by the utility operators as flexible and easy to operate. While these successes are a tribute to the agencies and individuals directly involved in the construction and test programs, it is also worthwhile to look at the history of the project to see how it came to be built and how the final configuration of the plant evolved.

In earlier papers, we have discussed the history of heliostat systems,[5] the philosophy of the central receiver concept,[6] and the early U.S. program leading to the decision to build a pilot plant of the central receiver type in the configuration of Solar One.[7]

Briefly, in 1969, Hildebrandt and colleagues conceived the idea that hundreds of megawatts of solar energy could be concentrated on an elevated central receiver by an array of thousands of large, independently-steered mirrors. It is easy to show that a concentration easily exceeding several hundred suns can be produced with a field of slightly curved heliostats. At such concentration, radiation and convection losses are small for a receiver satisfying the 500°C inlet temperature of utility turbines. The discovery that Francia[8] had already built and operated a geometrically similar system on a small scale (1 m^2 heliostats, 0.15 MW thermal power) was very encouraging, as was the fact that Trombe[9] had operated a field of 72 heliostats each of 45 m^2. Coupled with National Science Foundation (NSF)[10] and National Aeronautic and Space Agency

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[4] EPRI, FINAL REPORT: 10-MW(E) SOLAR-THERMAL CENTRAL RECEIVER PILOT PLANT, VOL. 1, REPORT ON LESSONS LEARNED (EPRI APO 3285), (prepared by Burns & McDonnell Eng. Co., Oct. 1983). *See also* Raetz & Riedesel, *supra* note 3.

[5] *See* Hildebrandt & Vant-Hull, *Power with Heliostats,* 198 SCI. 1139 (1977); Hildebrandt & Vant-Hull, *The Solar Tower, Six Years of Interdisciplinary Research,* 2 INTERDISCIPLINARY SCI. REV. 55 (1977).

[6] Hildebrandt & Vant-Hull, *id.*, and Vant-Hull & Hildebrandt, *supra* note 2.

[7] Vant-Hull, *Development of Solar Tower Programs in the United States,* 16 OPTIC ENG. 575-79 (No. 5, 1977); and Hildebrandt & Vant-Hull, *The Solar Tower . . .*, *supra* note 5.

[8] Francia, *Pilot Plants of Solar Stream Generation Stations,* 12 SOLAR ENERGY 51 (1968).

[9] Trombe, *Solar Furnaces and Their Applications* 1 SOLAR ENERGY 9-15 (1957); Trombe & Le Phat Vinh, *1000 kW Solar Furnace, Built by the National Center for Scientific Research, in Odeillo (France)* 15 SOLAR ENERGY 57-61 (1973); Trombe, Gion, Royere, & Robert, *First Results Obtained With the 1000 kW Solar Furnace,* 15 SOLAR ENERGY 63-66 (1973)).

[10] NATIONAL SCIENCE FOUNDATION, FINAL REPORT ON SOLAR THERMAL ELECTRIC POWER SYSTEMS (NSF/RANN/SE/GI-37815/FR/74/1,2,3) (prepared by Colorado State Univ. & Westinghouse Elec. Corp., Nov. 1974).

(NASA)[11] funded comparative analyses (flat plate, trough, dish, and central receiver systems), our NSF funded feasibility analysis,[12] conceptual design, and tests of heliostat beam projections over 1000 m led to the funding of four conceptual design studies by the Energy Research and Development Agency (now the Department of Energy, or DOE).

The success of Solar One can be traced to a number of reasons:

(1) Soundness of the basic concept.
(2) Excellence of the four design teams assembled for the preliminary design phase.
(3) Scaled experiments by the design teams on crucial subsystems (heliostat, receiver, thermal storage).
(4) Care of the selection committee in choosing a design with high performance potential, low risk, and high mass producibility.
(5) Commitment of Congress and DOE Solar Branch personnel to completion of the program.
(6) Continuity of experienced personnel throughout preliminary and final design, construction, supervision, and operation of test program.
(7) Dedication of a great number of individuals to making the program succeed.

With Solar One safely transferred to utility operation, it is appropriate to ask what the future holds for the central receiver concept, and what has been done to enhance this future.

THE REPOWERING PROGRAM

Since 1977, DOE has investigated a number of options, attempting to position the Central Receiver and the Solar Tower Program to gain advantage from windows of opportunity and to keep the various industrial teams intact.

In 1977, natural gas-fired boilers were placed under federal restriction. Consequently, fourteen studies of utility repowering and industrial retrofit were initiated by DOE,[13] each involving a plant owner and a solar design/engineering team. The idea was to use the central receiver concept to provide solar energy to substitute for natural gas in existing applications. These studies showed that the central receiver could fit into a wide array of applications, but also that the requirements are very application dependent. A wide range of temperatures, pressures, working fluids, and sizes were analyzed and appropriate designs derived. A significant number

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[11] NASA, Dynamic Conversion of Solar Generated Heat to Electricity (NASA CR-134724) (prepared by Honeywell, Inc. & Black & Veatch, 1974).

[12] NSF, Solar Thermal Power Systems Based on Optical Transmission, Final Report (NSF/RANN/SE/GI-39456) (prepared by Univ. of Houston & McDonnell Douglas Astronautics Co., 1975).

[13] Sandia Laboratories, Dept. of Energy Large Solar Central Power Systems Semiannual Review, Sandia Lab. Energy Report (Mar. 1980) (SAND80-8505).

of the plant owners showed interest in participating in a construction and operation phase, provided the government would cost-share the excess cost of the demonstration solar facility above its value as an energy producer. This high level of acceptance of the central receiver technology could not be exploited, however, for the political climate in 1980 had changed. The earlier drive for federal participation in the commercialization of the solar alternative was gone. In spite of historical evidence to the contrary for all previous new energy systems, as exemplified by the oil depletion allowance,[14] commercialization of new technologies was to be left to the marketplace. At this plane, the competition is fossil fuels which involve no significant capital outlay and for which the future price remains uncertain as, for example, the natural gas "bubble" of 1979-83 which substantially reduced the incentive to proceed with development of alternative energy sources. The solar manufacturer requires serial production of five large plants to achieve competitive prices, with the first plant costing perhaps twice its value versus a fossil-fueled plant. The buyer has no reason to pay the cost differential. If the manufacturer subsidizes the first plant in an effort to establish a market, there is nothing to prevent a competitor from profiting by this experience and underselling him on the second or third plant. Government involvement has ensured that no one has established a strong patent position.

Tax Credits

State and federal tax credits have been granted as an alternative to direct subsidies. Unfortunately, tax credits do not benefit the utilities which are the prime candidates for solar central receiver installation, because of the pecularities of the tax structure. The alternative is to have third party venture groups finance the installation and take advantage of the tax credits. The problem with this alternative is that in 1984, venture capital of this sort required a twenty-eight percent return on investment! Such a rate of return is difficult to achieve, even in the most favorable tax climate. The failure to extend or to provide "grandfather" tax credits has also added significant risk, because the federal solar energy tax credits are due to expire at the end of 1985.

Advanced Systems

In spite of the remarkable success of Solar One in proving the feasibility and operational readiness of the Central Receiver concept, this particular design has several well-known shortcomings. The water/steam configuration had been selected by the DOE managers very early in the program.

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[14] Battelle Pacific Northwest Laboratories, An Analysis of Federal Incentives Used to Stimulate Energy Production 268 (June 1978).

This selection was based on familiarity of the utilities with water/steam systems and on the availability of "off-the-shelf" pumps, valves, etc., for this technology.

Unfortunately, the water/steam working fluid introduces a number of undesirable features:

(1) Receiver peak flux limit of 0.3-0.6 MW/m^2.
(2) Heat transfer instabilities in the phase change region.
(3) High pressure (100-150 Bar).
(4) No feasible direct storage of steam.
(5) Feasible storage requires heat exchange to a low pressure fluid such as oil or salt; this process entails a significant loss in thermal quality.
(6) No simple/practical application of reheat Rankine cycle (10% loss of cycle efficiency from 41% to 37%).
(7) Conventional "off-the-shelf" pumps and valves tend to fail under frequent thermal cycles.

None of these problems is of such a nature as to preclude the operation of a water/steam system, but each decreases the efficiency and complicates operating procedures substantially.

All of the problems noted are overcome in the advanced central receiver systems using molten salt or molten sodium as a working fluid. There materials have low (negligible) vapor pressures at 550°C and superior heat transfer coefficients. Consequently, the allowable peak flux is increased to 0.85 and 2.0 MW/m^2 respectively, which allows reduced receiver size and higher thermal efficiency. These advanced systems have been implemented in current designs as listed in Table 1.

Table 1. Advanced Central Receiver Design

Power	Name	Site/Utility	Designer(s)	Fluid
30 MW_e	Solar Two	Carisa Plains/PG&E 36°N,120°W,Cal.	ESG of Rockwell (Bechtel)	Sodium
100 MW_e	Solar 100	Lucerne Valley/SCE 35°N,117°W,Cal.	MDAC Martin Marietta	Molten Salt Molten Salt
60 MW_e	Saguaro	Tucson/APS 32°N,112°W,AZ	Martin Marietta (Babcock and Wilcox)	Molten Salt

Storage is easily accomplished in either system by pumping warm fluid from a "warm tank" through the receiver into a "hot tank" whenever solar energy is available. Independent electrical generation is achieved any time hot fluid is available, by pumping the stored hot fluid through heat exchangers and steam generators to provide primary *and reheat* steam for the turbine at 550°C, if desired. Pumps and valves for this service have been developed for nuclear submarines, for the liquid metal fast breeder reactor, and for salt heater systems. Further tests for solar applications are currently underway.

SYSTEM DESIGN AND COMPONENT DEVELOPMENT

In an attempt to help the industry achieve commercialization, DOE in 1982 instituted a two-pronged effort created to help the design teams survive while simultaneously reducing the perceived technical risk. Thus, a team composed of Bechtel, the Energy Systems Group of Rockwell (ESG), and Atlantic Richfield (ARCO) Solar was funded to develop a final design for a 30 MW_e central receiver system utilizing a liquid-sodium-cooled receiver, for Pacific Gas and Electric. Because most of the sodium components (pumps, valves, steam generator) have been developed and tested under Atomic Energy Commission (AEC) funding, this concept is considered to be relatively ready for construction.

To support the alternative molten salt technology, Sandia Laboratories, in conjunction with a multitude of utility and industrial cost-sharing partners,[15] added to the 5 MW Solar Thermal Test Facility in Albuquerque, New Mexico, a salt transport loop, a molten salt steam generator, a 0.75 MW_e turbine generator, and other components to assemble a complete molten salt electric experiment (MSEE). MSEE uses the test facility heliostats, a refurbished 5 MW_t molten salt receiver, a new salt transport loop, existing hot and warm salt storage tanks of 6.5 $MW{\cdot}_h$ (hour) thermal capacity and a new 3.13 MW_t steam generator to drive the 0.75 MW_e turbine generator. A complete control system has been incorporated with the present test facility controls and the system will be used, not only to obtain test results on the various components, but also to test the various operating modes and to train several teams of utility operators in solar operations. The facility was dedicated in September of 1984 to a six-month operating phase. A further two and one-half year operating phase is under consideration. This Phase III program would strive for nearly automatic operation and provide added component tests.

Further support for the molten salt system will derive from a "pump and valve" test. Here, questionable components in the molten salt loop will be run through thermal and operational cycles to identify the best

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[15] Dedication of the Molten Salt Electric Experiment, Albuquerque, NM, 1984. Participants: Ariz. Public Service Co., Ariz. Solar Energy Comm., Black & Veatch Engineers-Architects, Babcock & Wilcox, U.S. Dept. of Energy, Electric Power Research Inst., Foster Wheeler, Martin Marietta, McDonnell Douglas, Olin Corp., Pacific Gas & Electric, Public Service Co. of NM, Southern Cal. Edison, and Sandia National Labs.

design concepts, failure modes, techniques for preventing failures, and methods for determining improvements prior to final plant design.

These operations were designed to add confidence to the design of the two contemplated molten salt cooled systems. Solar 100 is a pair of co-located salt cooled cavity receiver systems designed for Southern California Edison. A single cavity system powers a 100 MW_e turbine generator with a solar multiple of unity and a 27 percent capacity factor. The second system, to be added later, will charge a storage system, increasing the solar multiple to two and producing a 54 percent capacity factor. McDonnell Douglas and Foster Wheeler performed a preliminary design study[16] and teams headed by McDonnell Douglas and by Martin Marietta have offered competing proposals. Arizona Public Service Company also is sponsoring a salt-cooled central receiver design carried out by Martin Marietta, Black and Veatch, and Babcock and Wilcox. This 190 MW_t system incorporates a single cavity receiver and four hours of storage to repower a 60 MW_e turbine near Tucson. Each of these proposals and the ESG sodium receiver proposal were stalled for several months because of the inability to raise appropriate financing. Manufacturers are ready and willing to provide reasonable guarantees and the utilities are ready and willing to operate the plants. However, by July of 1984 it became obvious that none of the three organizations could assemble a suitable financing plan. Consequently, the current drive for commercialization has been stopped by uncertainty about oil prices, future tax credits, inflation, interest rates, elecrical demand growth, and remaining technical risk, real or perceived.

Applications

Solar central receivers can be designed to serve utilities in a variety of modes from baseload stand-alone to sun-following fuel savers. In selecting the mode, one must consider the cost of providing the service and the value of the product. Value includes capacity credits—cash payments to compensate for new plants the utility did not have to build to meet its projected load requirements. Capacity credits are high ($350/kW-yr) for base load plants (50-80% capacity factor), moderate ($250/kW-yr) for intermediate (15-50% capacity factor), and low ($170/kW-yr) for peaking plants (5-15% capacity factor).

Advance systems with two-tank storage offer a very simple method of hybridization. An oil or gas burning sodium or salt heater is very simple and compact and can easily be added in parallel to the solar receiver. Thus, hot working fluid can be provided on demand for a very small,

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[16] SOUTHERN CAL EDISON, MCDONNELL DOUGLAS CORP. & BECHTEL POWER CORP., SOLAR 100 CONCEPTUAL STUDY FINAL REPORT (Aug. 1982).

additional capital investment. With this configuration, intermediate plant capacity credit can be earned with a small cost for fossil fuel. The operating plan would be to use solar when available to meet intermediate load demands. Because such energy has zero fuel cost, it should be dispatched whenever it is available. When the "free" solar energy is not available, intermediate demand will be dispatched from the next cheapest source, which may well be a highly efficient combined cycle plant located elsewhere on the grid. If additional electricity is needed, the fossil burner on the solar unit will be dispatched next, before the less efficient peaking turbines. Thus, full intermediate load capacity credit is earned but only a relatively small part of the plant load (10-20%) is met by fossil fuels.

A second form of payment to an available power plant is on the basis of kilowatt hours produced and covers fuel costs and variable operation and maintenance costs. These payments are low for base load plants, which are designed to burn cheap fuel efficiently, and higher for the less capital intensive intermediate and peaking plants.

Stand-alone solar plants require excessive storage to earn significant capacity credit, for solar outages are unpredictable and can occur on several successive days. On the other hand, if a fossil fired base load plant (expensive and efficient) is added to the solar plant, economic reality recommends eliminating the solar plant; it is difficult for the solar plant with its high capital charge to compete with the low fuel cost of the hybrid. It seems as though the most sensible configuration is to select an advanced central receiver plant with a moderate sized molten salt or molten sodium storage unit. A low cost oil or gas burning heater can be added to the storage system. This configuration can provide reliability equal to or better than a fossil plant with very little fuel cost or environmental pollution.

Research

A corollary to the 1980 retreat from commercialization by the Reagan administration was an intention to sponsor long-term, high-risk, high-payoff research. This was eventually interpreted by DOE into programs on solar fuels and chemicals and on innovative solar specific or solar beneficial systems. This latter program has been somewhat difficult to identify. Two candidates seem to have survived:

Combined Photo-Thermal Process

In most cases, photo processes such as photovoltaic cells lose efficiency at high temperatures. Thus, it seems most desirable to separate out by means of a dichroic mirror the higher energy ultraviolet (UV) and blue photons useful to a solar cell, and to concentrate the remainder red and infrared (IR) photons to produce heat.[17] One possibility would be to produce heliostats using float glass with amorphous semiconductor solar cells formed on its front surface. If this were then coated with an IR reflecting UV transmitting dichroic mirror, one could have the best of both worlds. Alternatively, one could contemplate concentrating the UV on solar cells and the IR on the central receiver, although the mechanism for doing this with tracking heliostats is not clear.

Photo-enhanced (Activated) Thermal Processes

Certain aromatic chemicals which can be activated by ultraviolet light subsequently undergo an endothermic reaction.[18] The identification of appropriate reactions, catalysts, process parameters, and valuable end products can make this a suitable high payoff solar specific option.

FUELS AND CHEMICALS PROGRAM

The Fuels and Chemicals Program has engendered a wide range of activities. A principal tenet of this program holds that high temperatures, up to 1000°C, may be required. At such temperatures, metal tubes cannot be used and viable heat transfer media are not available. The alternatives are ceramic tubes, direct flux windowed reactors, new heat transfer materials which absorb sunlight directly, or the use of heat pipes which absorb energy in the high flux open receiver environment and deliver it into a chemical reactor at a more acceptable heat rate. All of these concepts are under intensive study by Solar Energy Research Institute (SERI), Sandia National Laboratories (Sandia), Georgia Institute of Technology, University of Houston, and other research institutions. Continued development may well show the feasibility of some of these concepts. The problem remains, however, that at these elevated temperatures the receiver losses become higher unless an exceedingly clever design is developed. Higher receiver losses require higher concentration and a smaller aperture to retain reasonable receiver efficiency.[19] However, the smaller aperture puts an increasingly burdensome constraint on the heliostat field. The heliostats must be more precise—therefore, more expensive, and must be closer to the receiver to avoid spread of the solar image, which requires a smaller field angle and higher tower for the same energy delivered. Finally, the insolation threshold for effective operation is increased, re-

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[17] Johnson, *Quantum and Thermal Conversion of Solar Energy to Useful Work*, in PROCEEDINGS OF THE SOLAR THERMAL RESEARCH WORKSHOP, GEORGIA INST. TECH. (1983).

[18] Private communication to author from W. Wentworth (Sept. 1984).

[19] Pitman & Vant-Hull, *Effect of High Receiver Thermal Loss on the Efficiency of Central Receiver Systems Having Optimum Heliostat Fields and Optimum Receiver Aperture Areas*, in PROCEEDINGS OF THE SOLAR THERMAL RESEARCH WORKSHOP, GEORGIA INST. TECH., *supra* note 17.

sulting in fewer operating hours because of increased sensitivity to turbidity, clouds, or low sun angles. The combination of effects can easily increase the cost of a kilowatt hour by 10 to 30% or more over the cost for normal 500°C operation. The more exotic receivers are also likely to be more expensive, as is heat transport and storage, if at all feasible. A viable concept for fuels and chemicals development must take all of these factors into account. It must also provide a system which can tolerate intermittent operation without incurring thermal stresses or high operating and capital per unit product costs.

ENERGY PAYBACK

A most important requirement for any new energy source is that it should have a good energy payback. This means that it should return to the economy the energy required in the construction and installation of all the equipment necessary for its operation in a period of time considered short in comparison with the design life of the facility. The ratio, design life divided by energy payback period, is a useful measure of the value of a facility. This ratio may conveniently be called the Energy Amplification Factor (EAF).[20] Energy systems which consume a natural resource will typically have a very high EAF if the energy produced, i.e., 10^8 barrels of oil, is divided by the energy invested—10^4 barrels of oil to build the rig and drill the hole. The EAF is reduced somewhat if the entire infrastructure required is prorated to each resource (oil pipe lines, refineries, exploration crews, etc.), but an EAF of 100 is still typical. Of course, if depletion of the natural resource were to be included in the equation, the EAF drops to less than unity. On average, more than one barrel of oil must be pumped for every net barrel delivered to the economy, so perhaps 0.95 for a good producer or 0.6 for a steam-flood heavy oil well, would be a reasonable figure. These numbers are reduced further if the initial energy investment is included as described above.

For a renewable resource such as solar, it is clearly inappropriate to charge the facility with depletion of the solar resource. However, the energy embodied in the relatively extensive collector system, including mining, refining, manufacturing, transportation, and installation must be accurately determined. To achieve a high EAF, one must clearly minimize the embodied energy and maximize the collection and transformation efficiency of the system.

A commercial scale central receiver system will convert incoming sunlight to 500 to 600°C working fluid at about 67% efficiency; using a reheat turbine cycle can convert this thermal energy to electricity at 42% efficiency. Allowing 5% collector parasitics and 5% receiver-converter par-

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[20] Hildebrandt & Vant-Hull, *supra* note 5.

asitics means converting sunlight to process heat at 63% efficiency, and to electricity at 25% efficiency. A planar or cavity receiver at 200 m elevation can collect energy effectively from 9,000 heliostats, each 57 m^2. Recent EAF analysis of such a system using a molten salt as the receiver fluid and a reheat turbine has given results in good agreement with our earlier published results for a 100 MW_e water-cooled system. Without reheat, the gross cycle efficiency was 37% and the overall plant efficiency was 22%.

Rather than discuss our undocumented current results,[21] we will update the results from our earlier analysis.[22] Both studies give energy payback times of approximately 6 months (thermal) or, using 33.3% as a net thermal to electrical conversion efficiency, easily achieved for the 500°C steam produced, about 18 months assuming all energy requirements can be satisfied by electricity.

The 100 MW_e plant we analyzed previously was the prototype selected for emulation by the 10 MW_e pilot plant built near Barstow, currently operated on the grid of Southern California Edison. Thus, this plant has adequate definition to include all of the required parts; experience has shown that the design is viable and easy to operate. In the selection procedure, personnel from DOE and Sandia evaluated three competing designs. The design selected, which is the one evaluated here, employed an external receiver and a surrounding field of heliostats, as at Solar One. The resulting receiver is small in design and much lighter than the cavity receivers employed in the two competing designs. The use of the external receiver also allows two to three times as many heliostats to be placed close to the tower in a 360° rather than a 120° field of view. As a consequence, the tower can be much shorter and still serve an adequate number of heliostats. The small, lightweight receiver also reduced the strength requirement and, hence, the weight of the tower. Finally, the heliostat selected was intrinsically a low mass design. A single pedestal supports the two axis actuators that control the orientation of a torque tube from which the steel backed mirrors are supported by welded struts. Alternative designs involving heavy yokes or external framework were rejected, partly because it was recognized that the extra weight would entail a cost penalty.

In fact, DOE and the solar industries have supported a continuing research program to reduce the cost of heliostats. In the process, heliostats

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[21] F. W. Lipps & L. L. Vant-Hull, System Design Studies for Central Receiver Application, Topical Research Report, submitted for transmittal to NTIC, SERI contract no. RX 4-04006-1, (1983)

[22] Meyers III & Vant-Hull, *The Net Energy Analysis of the 100 MW_e Commercial Solar Tower*, in PROCEEDINGS OF THE ANNUAL MEETING OF THE AMERICAN SECTION, INTERNATIONAL SOLAR ENERGY SOCIETY 786 (1978); *see also* Meyers III & Vant-Hull, *The Net Energy Analysis of the 100 MW_e Commercial Solar Tower*, Part II, NTIS Report No. ORO 5178-78-2 (May, 1978).

have grown from 30.5 m^2 to nearly 160 m^2. It is interesting to evaluate the effect this has had on the embodied energy per square meter of heliostats, including an allowance for transportation of materials from the mill to the site and a suitable allowance of 15 to 25% for energy consumed in manufacturing. Table 2 reproduces data derived from our preliminary 1976 study (A), our published 1978 work (B), our 1983 analysis of the second generation heliostat (C), and our model of a generic "optimized second generation" heliostat (D). For consistency, the McDonnell Douglas heliostat designs have been used throughout; thus we see the evolution of a design rather than major design changes. Recent heliostats from all U.S. manufacturers bear a very close resemblance to designs C and D, and component weights will not be significantly different. In fact, D is more an industry average than it is a proprietary example. Specific manufacturers will select from competing options. For example, panel rigidity may be achieved by use of a lightweight aluminum honeycomb, or by the use of heavier steel stiffening ribs; a box beam may be used for the main structural element, rather than a torque tube, etc. Such design trades play an important role in producing lowest cost-competitive results, but competition will ensure that the cost and weight of competing elements will not vary greatly.

A new generation of ultra-lightweight stretched membrane heliostats is under development within SERI and Sandia [23] but a commercial prototype has not yet been defined. It is anticipated that, if successful, this development will reduce heliostat cost several fold, mainly by virtue of lower materials requirements, i.e., lower embodied energy.

Revising Table 6 of the 1978 work[24] to incorporate the second generation, type C, heliostat and using estimated 1980 energy intensities,[25] we can develop the materials requirement and energy equivalent for a 100 MW_e water steam system with a solar multiple of 1.7 and 6 hours of storage in an oil/rock thermocline system. See Table 3. This non-reheat plant operates at a gross cycle efficiency of 37% and a net efficiency, after supplying parasitic electrical needs, of 33.7% to provide 446,000 MW_eh to the grid annually for a site with insolation comparable to Barstow, California. It is appropriate to reduce this energy production by an additional 2% to account for thermal oil decomposition and for the energy cost of plant operation and maintenance, exclusive of electrical parasitics. Solar plant electrical parasitics of 4.4% have already been accounted for. Thus, 437,000 MW_eh are available as a net energy gain from the system annually. The total energy embodied in the facility, exclusive of the

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[23] L.M. Murphy & D.V. Sallis, Analytical Modeling and Structural Response of a Stretched-Membrane Reflective Module, SERI/TR-253-2101 (June, 1984).

[24] Meyers III & Vant-Hull, *supra* note 22.

[25] Lipps & Vant-Hull, *supra* note 21.

Table 2

Heliostat		Steel	Glass	Concrete	Zinc	Plastic	Trans/ Copper	Manuf.	Total	per/m^2
A. Conceptual Design—1975										
30.4 m^2	(Mg)	.807	.488	2.420*		.009	.013		3.73	.123
	(MW·h)	5.03	1.5	.78		.025	.285	20%	9.40	.309
				* +3.5 Mg sand ballast						
B. Preliminary Design—1978										
37.0 m^2	(Mg)	1.379	.611	6.733*	.061	.078	.009		8.87	.240
	(MW·h)	8.605	1.970	2.180	1.280	.194	.197	33%	19.18	.518
				*heavy precast foundation in this design						
C. Second Generation—1981										
57.3 m^2	(Mg)	1.746	.879	4.271*	.038	.054	.023		7.01	.122
	(MW·h)	13.322	2.559	1.251	.794	.731	.464	23%	23.52	.410
				*drilled and poured foundation						
D. Optimized 2nd Generation 1983										
95 m^2	(Mg)	2.007	1.818	5.338*	.064	.091	.023		9.34	.098
	(MW·h)	15.32	5.291	1.564	1.327	1.223	.464	24%	31.22	.329
				*drilled and poured foundation						

Table 3. Tabulation of Component Weights in Mg and Embodied Energy in MW·h 100 $\mathrm{MW_e}$ Solar Central Receiver Plant, Capacity Factor 46%

	Steel	Alloy Steel	Glass	Concrete	Al	Cu + Zn	P&A*	M&C*	T*	Total Energy
Heliostats	25,863Mg		13,020	63,266		904	799	11%	13%	
14,813 @ 57.3 m^2	197,350MW·h		37,895	18,536		18,668	10,758	30,885	35,270	349,358
Field Wiring	16	17	3	16	237	85.6	13.8	10%	4%	
and Transformers	122	155	10	5	18,315	1,750	190	2052	820	23,419
Receivers and	653	535	1					26%	7%	
Structure ¢ @ 266 m	4,982	5296	3					2672	718	13,671
Vertical Pipes	174	180			2			10%	3%	
(x2 for others)	1,328	1740			144			320	100	3,633
Tower	1,266			41,757				10%	20%	
242 m	9,660			12,235				2659	5,170	29,724
Storage System	2,336		106	5,820	19	6	8,212**	10%**	9%	
including heat	17,823		308	1,705	1,467	120	11,045	4030	2,826	39,324
exchangers										459,130
Total weights	30,308	732	13,140	120,859***	258	966	9,025			

*P&A plastics and adhesives; M&C—manufacturing and construction; T—transportation

**Thermal oil, assumes 90% of oil recovered after 30 years.
Oil makeup during operation taken as a plant parasitic.
No contribution to M&C (included in oil energy allocation)

***Cement ~ 12% by weight of concrete, cement = 15,400 T
Aggregate = 106,000T (concrete) + 81,000T (thermal storage media)
Total weight exclusive of aggregate and recoverable oil = 69,859 metric tons

electrical plant, is 460,000 MWht. Thus, all the thermal energy required to provide the plant will be returned as electricity in 1.05 years. The fuel saved by operation of this plant could be burned to provide heat or energy where needed. Assuming an overall efficiency of 33.3% for the displaced fuel burning plant, the fuel saved would replace the embodied energy in 35% of a year, or 128 days. Assuming 100% of the thermal storage oil as a capital energy cost, although 90% of the oil can be recovered at decommissioning of the plant, increases the 460,000 MWht to 560,000 MWht, the payback period increases to 1.28 years, and the replacement of embodied energy to 42.7% of a year, or 156 days. Thus, the EAF is 20-30 for electric production and 60-90 for heat production.

Future developments include use of an advanced receiver fluid such as sodium or molten salt which allows greater receiver efficiency and direct storage of the sodium or salt. The associated 10% improvement in average performance is in addition to a 10% gain in turbine efficiency resulting from use of a reheat cycle. Substitution of the 95 m^2 heliostat also promise a 20% reduction in energy cost of the collector field, while the stretched membrane heliostat currently under development may provide a 50% reduction. Thus, an overall improvement of 35% or more in the EAF may be expected as the technology matures.

Comparison to Other Energy Analyses

In the past ten years a number of net energy analyses on solar thermal facilities have been reported. Several of these show results substantially less favorable than our worst case of 5(15) months for thermal(electrical) payback, and it is worthwhile to see why.

Slesser,[26] probably because he is working in Scotland, home of the umbrella, chooses to evaluate a *flat plate collector* working over the temperature range of 50 to 60°C, powering an organic Rankine cycle turbine through a heat exchanger. To the surprise of no one, he determines the parasitic energy requirements to be ~ 3 times the electricity produced while the embodied energy in this impractical system is ~ 115 times the annual turbine output. Somehow, he uses the result to imply that the 1.48 year paybck period quoted by Enger and Weichel[27] for a central receiver system is in error. Slesser chooses to make this comparison because "the thermodynamic quality of the energy coming from the solar capture device is frequently of very low quality."[28] The comparison is erroneous; the central receiver plant evaluated by Enger and Weichel operated at normal

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[26] Slesser, *Can Solar Energy Replace Fossil-Fissile Energy Sources?* 25 SOLAR ENERGY 426 (1980).

[27] Enger & Weichel, *Solar Electric Generating System Resource Requirements*, 23 SOLAR ENERGY 255-61 (1979).

[28] Slesser, *supra* note 26.

steam Rankine cycle temperature of ~500°C to produce electricity sufficient to pay back its total embodied energy in 1.48 years, a number very similar to the 1.05 to 1.28 years we quote. Slesser's ability to design a poor solar system does not imply that a competent engineering group cannot design a good one!

Grimmer[29] takes a somewhat different approach in discussing solar energy "breeders." His "favorable" result is much less favorable than it should be. Grimmer evaluates a central receiver system and has very accurate data for his materials analysis. Unfortunately, he has chosen to evaluate the 0.4 MW_t solar test facility at the Georgia Institute of Technology. This very fine solar furnace uses 550 mirrors, each of area .78 m^2 and each incorporating its own 13.6 kg actuator. The entire array is assembled on a monolithic steel framework in Atlanta, where the direct beam insolation is about one-half that in the Southwest. Excellent as a test facility and suitable to demonstrate power production, this device was never viewed as either commercial or typical of a power generating facility. Nevertheless, Grimmer derives a thermal payback period of 4.3×10^9 BTU/2.1×10^9 BTU per year = 2.1 years. In the Southwest, this figure would be reduced to approximately one year due to the improved insolation, and utilization of a more commercial design that allows a substantial weight reduction would lead to a result in nominal agreement with ours.

Seymour Barron[30] has evaluated the central receiver technology for EAF. He has widely reported results which are substantially less favorable than ours, yet he has used the basic Sandia evaluation of pilot plant design options, or derivatives of this work, as his basic reference. This reference is compatible with our references, yet his result is half an order of magnitude more pessimistic. Why? To understand, one must return to his original analysis and also to the original Sandia document. This was a report evaluating preliminary designs by three industrial design teams for a 10 MW_e Central Receiver pilot plant designed as a scaled version of a 100 MW_e commercial plant. These designs were quite varied. One used a massive, tall tower to support a heavy cavity receiver illuminated by a relatively efficient north heliostat field. A second used an even taller tower, with an exceedingly heavy downward looking cavity designed to have low convection losses, viewing a very constrained but efficient surround field. The third used a light external receiver illuminated by an unconstrained surrounding field of heliostats. In this case, somewhat higher

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[29] D.P. Grimmer, *Solar Energy Breeders*, in 2.2 PROCEEDINGS OF THE ANNUAL MEETING OF THE AMERICAN SECTION, INTERNATIONAL SOLAR ENERGY SOCIETY 558 (1978).

[30] The evaluation of Seymour Barron, Vice President of Burnes and Roe, was entitled *Solar Energy—Will it Conserve Our Non-Renewable Resources?*, PUB. UTIL. FORTNIGHTLY 617 (Sept. 1978).

receiver losses were accepted in trade for a much shorter lightweight steel tower and freedom to use a broad heliostat field.

The selection team chose the third option along with the heliostat showing the potential for lowest weight. For this heliostat design, DOE proceeded to fund competitive prototype heliostat construction, test, and evaluation work to ensure availability of lightweight, mass-producible, effective heliostats. The pilot plant, Solar One, was built according to the selected design and has operated up to design expectations during the test phase. Operation by Southern California Edison between 1984 and 1988 will produce hard data on reliability and efficiency.

Barron's approach to the three preliminary designs was to assume the worst. Thus, he evaluated a system comprising the most unfavorable elements of each design, i.e., the upper limit of the quoted range of each component weight in the Sandia report. Effectively, he chose the tall, massive concrete tower, the heaviest heliostat, and the most massive receiver. These features were inappropriately combined with the lowest efficiency selected from the three designs for each element.

To be on the "safe" side, he then increased the estimate by 50% to allow for weight increases as the design matured whereas, in fact, weights have been pared substantially. Finally, although no design called for it, he added a 15 cm thick concrete apron over the entire field (50,000 m^3). Needless to say, Solar One is operating without the apron and with no troubles from local sand or dust. Nearby farming is more of a problem. The result of Barron's conservative approach is an energy payback period of 4.6 years for electrical payback, a number three to four times our estimate.

In contrast, our analysis of the embodied energy and energy payback for the pilot plant [31] uses final design data which differs only slightly from the as-built plant. These data include parts counts, detailed listings of wall thickness, pipe runs, torque tube sizes, casting weights, and other specifications. Our later analysis of a commercial plant is for that plant which was scaled in size to produce the pilot plant design. Our current update, in which we optimize the design with respect to embodied energy, uses the advanced salt receiver concept as embodied in the Solar 100 preliminary design done by Southern California Edison, MDAC, and Bechtel. In this study we also obtain thermal energy payback times of less than six months. Thus, we have considerable confidence in the basic accuracy of our results, particularly in comparison to the completely inappropriate analyses done by some others in the field.

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[31] *See* Meyers III & Vant-Hull, *supra* note 22.