4. The SEGS Experience

Responsibility: DK

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4. The SEGS Experience

4.1 Early Parabolic Trough Development

In the 1880's, the Swedish American John Ericsson powered his hot-air engine with a parabolic trough, but it was not until 1912 that the trough was used in any significant way for power generation. At that time Frank Shumann of England and C.V. Boys of the United States constructed a 45 kilowatt steam-pumping plant in Meadi, Egypt using parabolic trough collectors 62m long and 4m aperture with a total aperture area of 1,200 m^2. Despite the plant's success, it was shut down in 1915 due to the onset of World War I and cheaper fuel prices.

Interest in the technology was not renewed until the 1970's and 1980's as a response to the oil price crisis, at which time the US Department of Energy (DOE) as well as the German Ministry for Research and Technology sponsored the development of a number of parabolic-trough process heat and water pumping systems. In 1981, a 500 kW_e International Energy Agency system for electric power production using parabolic troughs was tested in Tabernas, Spain at the Plataforma Solar de Almeria facility.

To date, the most noteworthy privately financed, non-electric parabolic trough facility in the world is the successful 5,580 m^2 industrial process heat system in Chandler, Arizona, which has been operating since 1983. The system generates and stores thermal energy for copper-plating electrolyte tanks.

4.2 Commercialization of the SEGS Plants

From 1984 to 1991, parabolic trough system deployment took a dramatic leap forward with the development of a series of 15 MW_e to 80 MW_e commercial solar electric plants by Luz International Ltd. Prior to this step, the company spent several years developing the components and systems at a test facility in Jerusalem, and was responsible for the construction and operation of two process heat facilities in Israel. The nine Luz-developed power plants, with a total generation capacity of 354 megawatts of electricity, are called SEGS (**S**olar **E**lectric **G**enerating **S**ystems) and are operating routinely in the Mojave desert of southern California. Table 4-1 gives key characteristics of the nine plants.

From 1984 to 1991, parabolic trough system deployment took a dramatic leap forward with the development of the SEGS plants

The first step occurred in 1983 when Luz negotiated a 30-year contract with the utility Southern California Edison to sell electricity from two plants - a 14 MW_e facility followed by a 30 MW_e facility. These plants, SEGS I and SEGS II, were the start of the unique and successful SEGS series. Besides being instrumental in development of the plants, Luz served as the designer and supplier of the solar fields.

The SEGS I facility consists of 82,960 m^2 of collector aperture area used to heat a hydrocarbon-based heat transfer fluid, which in turn passes through a heat exchanger to generate steam at 35.3 bar for a conventional steam-turbine power cycle. In this system the solar field energy is used to preheat feedwater and generate steam, and a natural-gas-fired independent superheater raises the steam temperature to 415ºC. Two large hot and cold storage tanks (with a capacity of about 3,220 m^3 each) provide enough storage to produce nearly three hours of full-load turbine operation. The solar field was constructed entirely of Luz LS-1 collector technology. SEGS I went on line (i.e., it first generated electricity and was synchronized with the SCE grid) in December, 1984.

Unit	I	II	III	IV	V	VI	VII	VIII	IX
Capacity, Net MW	13.8	30	30	30	30	30	30	80	80
Land Area, hectares (approx.)	29	67	80	80	87	66	68	162	169
Solar Field Aperture Area, hectares	8.3	19.0	23.0	23.0	25.1	18.8	19.4	46.4	48.4
Solar Field Outlet Temperature, °C	307	321	349	349	349	391	391	391	391
Turbine Efficiency, %									
Solar Mode	31.5[a]	29.4[b]	30.6	30.6	30.6	37.6[c]	37.6	37.6	37.6
Gas-Fired Mode	-	37.3	37.3[d]	37.3	37.3	39.5	39.5	37.6[e]	37.6
Turbine Steam Inlet Conditions, Solar Mode									
Pressure, bar	35.3	27.2	43.5	43.5	43.5	100	100	100	100
Temperature, °C	415[a]	360	327	327	327	371	371	371	371
Annual Performance (design values)									
Solar Field Thermal Efficiency, %	35	43	43	43	43	43	43	53	50
Solar-to-Net Electric Efficiency, %	9.3	10.7	10.2	10.2	10.2	12.4	12.3	14.0	13.6
Net Electricity Production, GWh/yr	30.1	80.5	91.3	91.3	99.2	90.9	92.6	252.8	256.1
Natural Gas Use, 10^6 m^3/yr	4.8	9.5	9.6	9.6	10.5	8.1	8.1	24.8	25.2
Water Use, 10^3 m^3/yr (approx.)	164	427	467	467	507	364	370	1011	1024
Unit Cost, $/kW	4490	3200	3600	3730	4130	3870	3870	2890	3440

a) Steam generated by solar energy, superheated by natural gas (18% of energy input)
b) In solar mode, steam is generated <u>and</u> superheated by solar energy (SEGS II-IX)
c) Reheat turbine (SEGS VI-IX)
d) In gas-fired mode, turbine inlet steam conditions are 105 bar/510°C (SEGS III-VII)
e) HTF heater introduced; steam conditions identical in solar mode and gas-fired mode

Table 4-1 Characteristics of the SEGS Plants

Work commenced on SEGS II in early 1985. This plant was a 30 MW_e facility with a solar field comprised of both LS-1 and the next generation LS-2 collectors[1]. The SEGS II plant introduced a major and very important design concept to the SEGS configuration. A natural gas boiler was added[2] to the plant configuration in parallel with the solar field. That is, turbine steam can be supplied either by the solar field or by the natural gas-fired boiler. Furthermore, a solar superheater was added so that the plant could also operate completely on solar energy alone in the solar mode of operation. The concept of a supplementary fossil-fired source of energy was incorporated in all subsequent SEGS plants. Once the concept of a *hybrid* plant able to operate on either solar energy or natural gas was conceived, its benefits became apparent. Such a plant has the capability to operate under conditions of low solar radiation (e.g., inclement weather or night) and provides a reliable capacity for any special needs that the utility might have. By US federal law, the energy supplied by natural gas is limited to 25% of the total effective annual thermal plant energy input. Figure 4-1 shows a illustrative layout of a SEGS plant with its solar field and steam Rankine cycle power block.

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[1] A small portion of the SEGS I solar field - 11,280 m^2 - are also LS-2 collectors.

[2] The initial impetus to this change in SEGS II was the fact that thermal storage using oil would have been prohibitively expensive for two reasons. First, SEGS II was designed to operate at a higher solar field temperature, requiring a change from a mineral oil circulating through the solar field to a higher temperature synthetic oil composed of a diphenyl/biphenyl-oxide mixture. The new oil was much more expensive, costing about $2.60/liter rather than $0.40/liter. Second, a 30-MW plant would require approximately twice the storage volume for 3 full-load hours of storage capacity. Hence the storage oil alone would have cost on the order of $17 million USD.

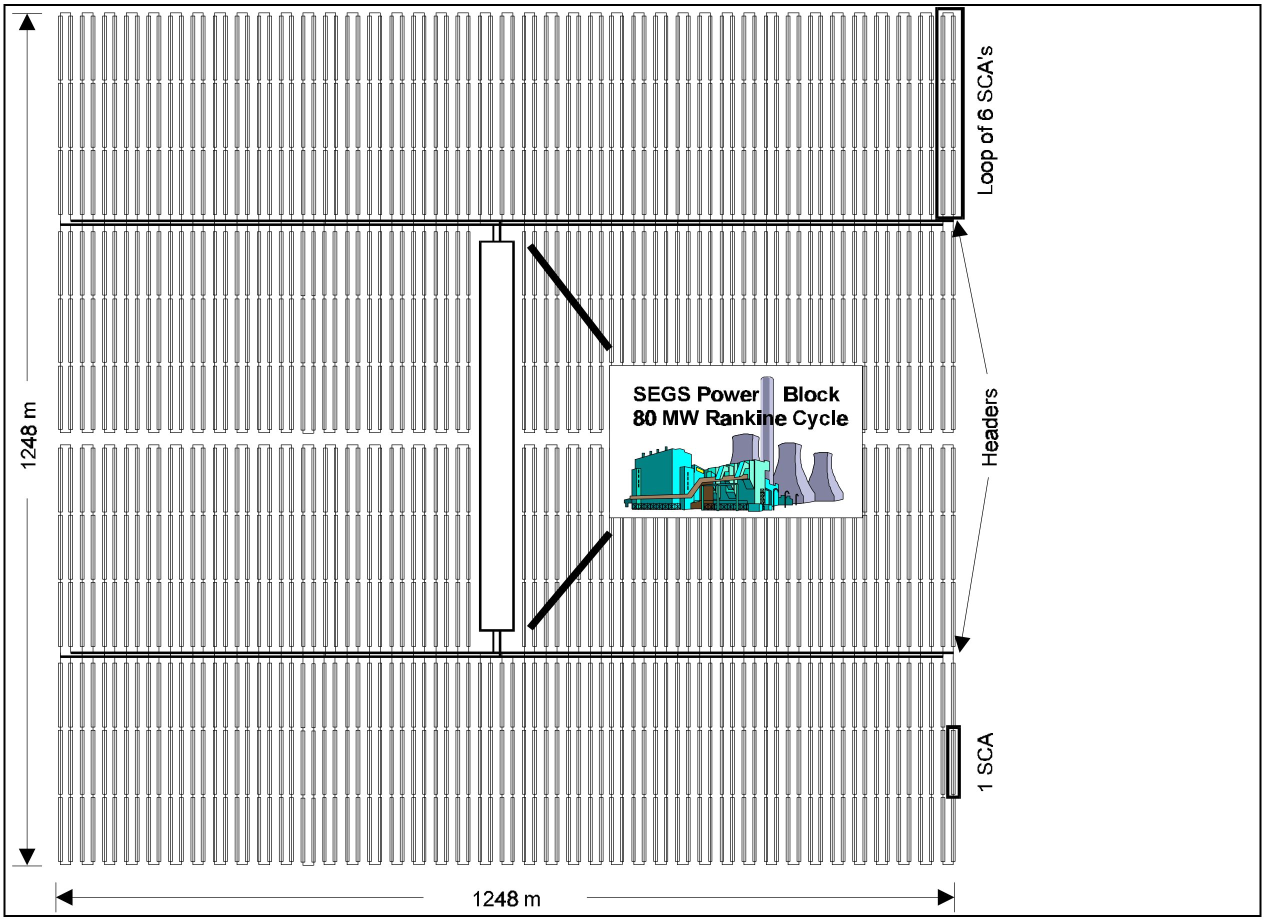

Figure 4-1 Illustration of a Typical SEGS Plant Layout

Luz continued developing 30 MW_e SEGS plants on a yearly basis, up to the construction of SEGS VI and VII in 1988. An adjacent photograph shows an aerial view of the Kramer Junction site where SEGS III-VII are located. A close-up picture of a row of LS-2 parabolic trough collectors is also shown. Several factors contributed to advances in collector and plant performance as SEGS III through SEGS VII were developed. Improvements in the collector technology led to higher temperatures, which in turn allowed higher steam-turbine cycle efficiencies, largely due to the introduction of a reheat turbine cycle.

Each facility was developed as an independent power producer which sells power to the local utility - in all cases Southern California Edison Company (SCE) - under terms of a power sales agreement between the owners of the plants and the utility. The owners of the plants are investor groups typically composed of large corporations, insurance firms, utility investment arms and some individual participants. The role of Luz was to develop the projects from inception to operating plants, and to operate the plants under separate contracts to the owners. In 1989 and 1990 Luz increased the plant size to 80 MW_e with the construction of SEGS VIII and IX. The Luz company failed in 1991 due to financial difficulties prior to the development of the planned SEGS X plant.

Each SEGS was developed as an independent power producer which sells power to the local utility

The cumulative debt and equity investment in the SEGS plants totaled $1160 million USD. With each plant taking approximately one year to build utilizing an average construction work force of about 400 persons (maximum labor force at the peak of construction can reach over 800 persons), these plants represent about 3,200 construction job-years.

4.3 Observations on SEGS Plant Performance

The nine SEGS plants have operated in a routine manner since their installation. Performance of the plants has been uneven, though always acceptable to the owners and consistently excellent in some aspects, as shown in the Figures to follow. The cumulative electrical output and earned revenues of the nine plants since the inception of the SEGS facilities are estimated in Figure 4-2. In most plants, performance was hampered in the early years due to problems with construction practices exacerbated by short installation times. After Luz ceased operations in 1991, certain solar field spare parts were not replaced immediately and solar field performance has tended to temporarily degrade as a result.

Observing the development and operation of the SEGS plants to date, it is clear that much has been learned which will benefit future parabolic trough plant installations. Both through the evolution of operating and maintenance methods since the mid-1980's and the joint venture between the KJC Operating Co. and Sandia National Laboratories (see Section 5), better operating techniques, observations on improved design practice and lower maintenance costs have evolved. Samples of these advances are described in Section 5.

More detailed examination of the five 30-MW plants at the Kramer Junction site offers additional insight into solar plant operation and performance. These plants have committed owners, a dedicated O&M operator and have engaged in a significant program of technology and O&M method improvements in partnership with the US Sandia National Labs since 1992. Figure 4-3 compares the performance of the five plants over seven years with respect to the attainment of capacity factors[3] during the on-peak period. This period, from 12:00 to 18:00 on weekdays during June through September, provides over 65% of the annual revenues from the sale of electricity due to the terms of the power purchase agreement with the utility. Largely from solar energy but with some supplementary gas-firing, the plants have typically exceeded design capacity, even achieving levels approaching 110% for the full on-peak period. The uniform and high output in 1995 at 109.5% capacity factor shows a maturity of plant O&M practice resulting in closely-controlled electricity production for each plant. Based on this, the same high level of performance is projected for 1996.

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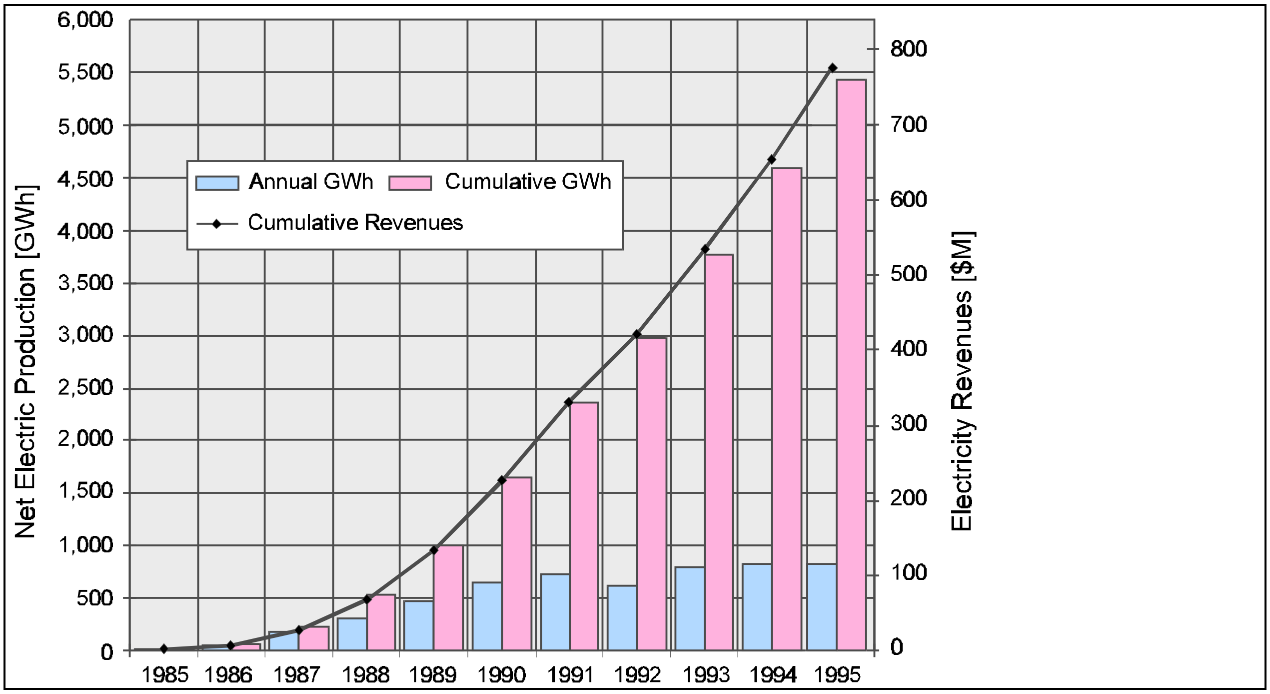
[3] Capacity factor is the net electrical output over a specified time period divided by the maximum possible output during that period operating at design capacity. A solar-only plant is limited to lower capacity factors by definition due to the periodic availability of solar radiation, approximately 2000-2500 full load hours or a capacity factor of about 25%.



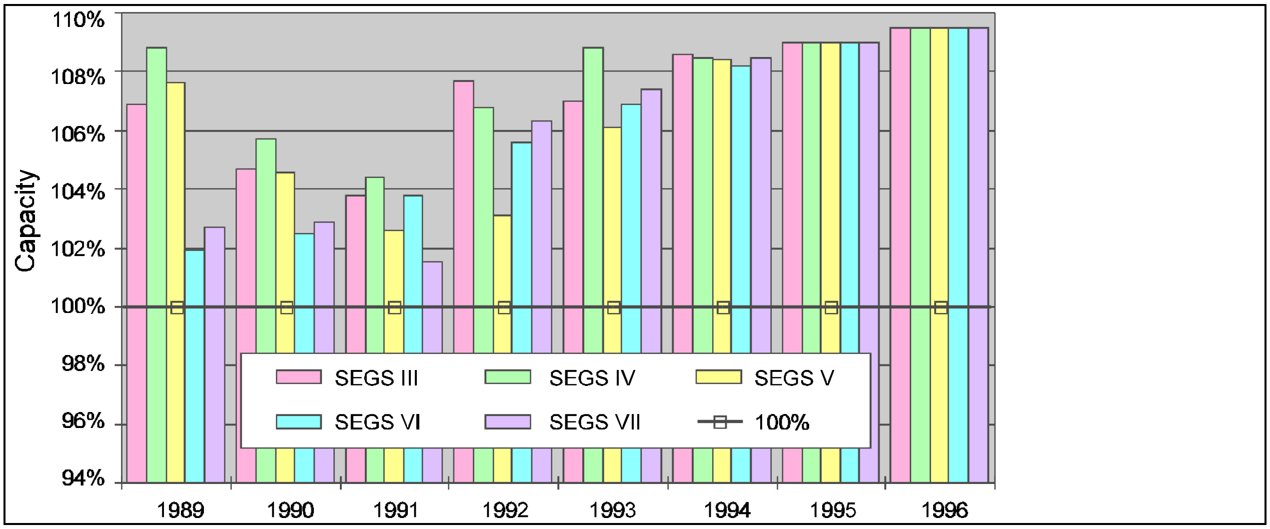
(Courtesy of KJC Operating Co.)

Figure 4-2 Cumulative Performance of SEGS I-IX through 1994

Largely from solar energy but with some supplementary gas-firing, the plants have typically exceeded 100% design capacity during the summer on-peak period

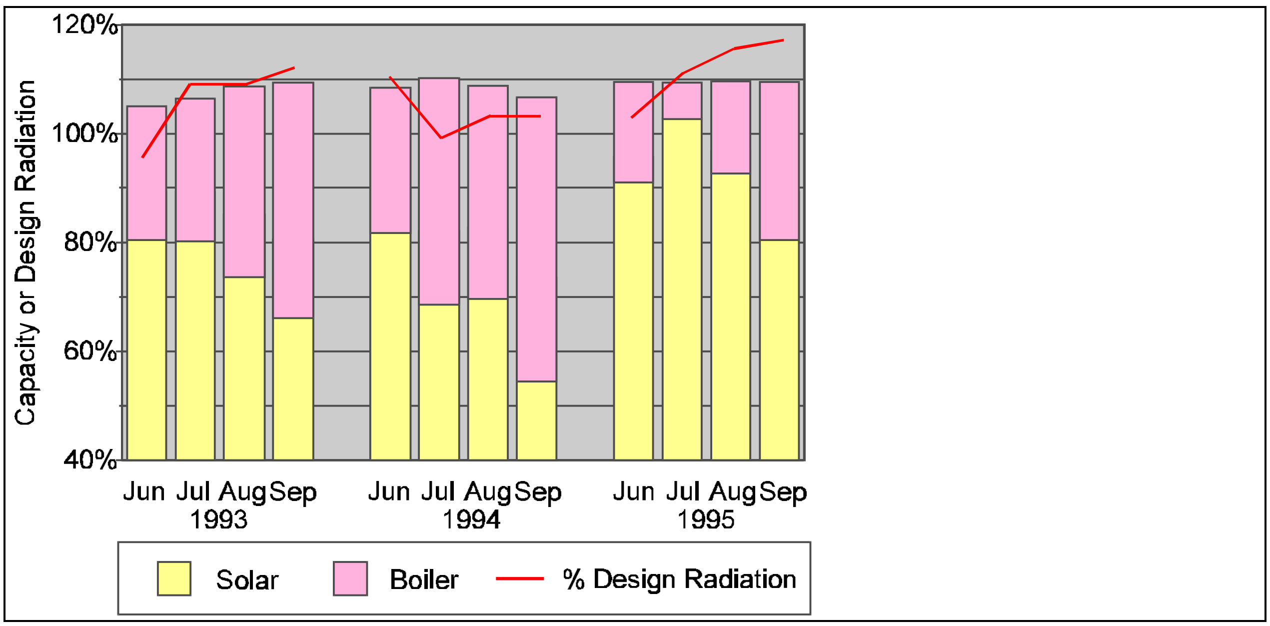
Figure 4-4 emphasizes this point by vividly illustrating the improvement in solar field electrical production over the years 1993 through 1995. The upper lighter portion of the stacked bars shows the contribution to monthly on-peak production from the use of fossil fuel. By 1995, the use of supplementary natural gas was significantly decreased due to improved plant operation and slightly higher insolation. The small rise in monthly gas use from July through September of that year results because of the normal decline in seasonal effectiveness of the solar resource (less flux in the aperture plane of the collector), even though direct normal insolation is increasing. An important contributor to the excellent performance in 1995 was the replacement of broken receivers[4] and mirrors, bringing the solar field up to a near-new condition.

[4] Called Heat Collection Elements, or HCEs, in the SEGS terminology



(Courtesy of KJC Operating Co. Also see Annex B, Cohen 1995)

Figure 4-3 On-Peak Performance of SEGS III-VII for 1987-1994



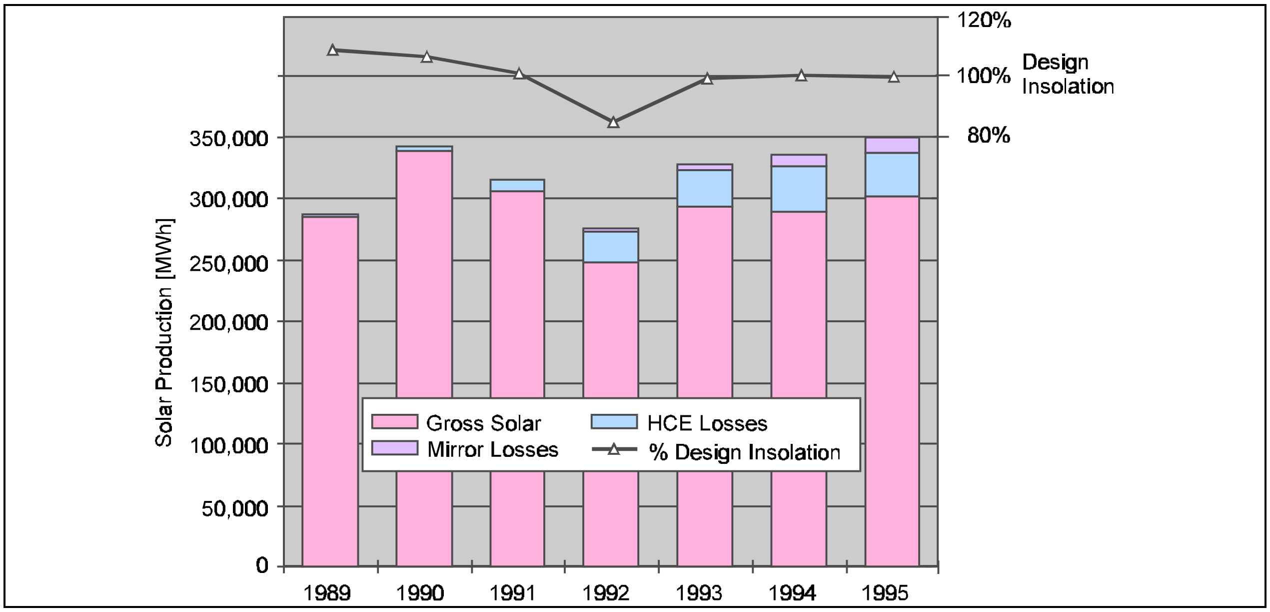
(Courtesy of KJC Operating Co. Also see Annex B, Cohen 1995)

Figure 4-4 Monthly On-Peak Performance of SEGS VII for 1993-1995

Gross solar electric production for the year is dependent on good O&M results but limited by the annual solar radiation. Figure 4-5 illustrates the sum of the total gross solar annual production for the five plants for the years 1989-1995. The solar radiation is shown as a percent of the design value (2725 kWh/m^2-year). The reduction in 1991 and 1992 results from the world-wide effects of the volcanic eruption of Mt. Pinatubo in the Philippines. As the performance since 1991 was unnecessarily limited by the lack of several critical solar field spares[5], the bars show not only actual performance but also the possible performance were the solar field condition at normal operating levels. In 1995 the owners placed orders with Solel Solar Systems (Israel) and FLAGSOL

[5] Not available either due to an interruption in production (HCE's) or to owner purchase decisions (HCE's and mirrors).

(Germany) for sufficient HCE's and mirrors to bring the Kramer Junction solar fields to a good operating status.



(Courtesy of KJC Operating Co. Also see Annex B, Cohen 1995)

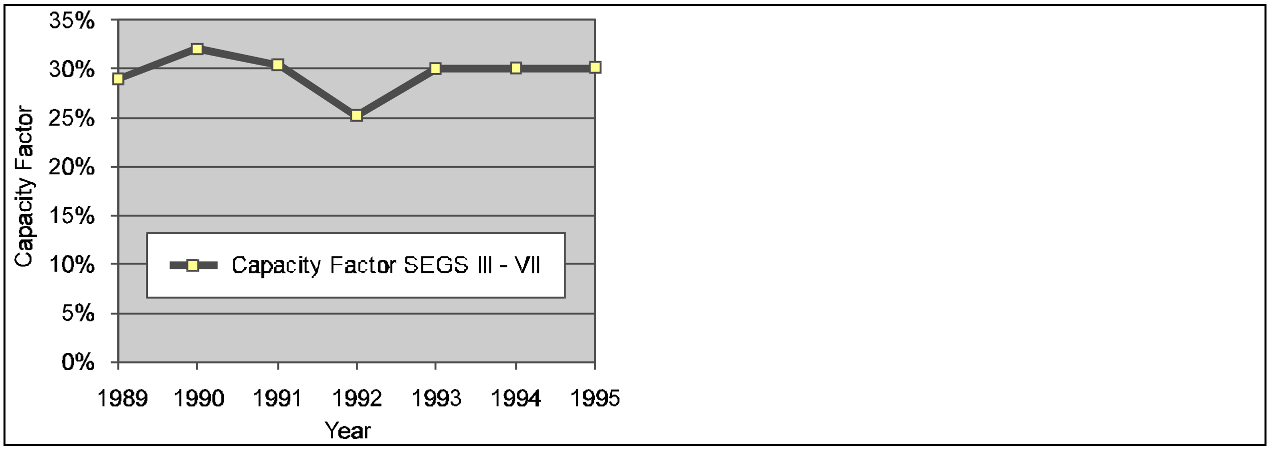
Figure 4-5 Annual Performance of SEGS III-VII for 1989-1995

Annual capacity factors averaged for the 30-MW plants at Kramer Junction are illustrated in Figure 4-6 for the years 1988-1995. The capacity factors are averaged over the entire year, in contrast to the on-peak period shown above, and include electricity production by both solar energy and natural gas. This measure, on the order of 25-30%, responds directly to the influence of the solar radiation.

The solar-to-electric efficiency of a solar plant gives the ratio of the net electric output to the direct normal radiation available to the plant. Plant conditions[6] at Kramer Junction are good, characterized by mid-day *peak* net solar-to-net electric efficiencies measured at over 16% at both SEGS VI and VI in the summer of 1995. If adjusted for missing spare parts (a temporary condition), this efficiency figure increases to 18%. In 1995 *annual* solar-to-net electric efficiencies of the SEGS VI and VII plants were about 10%.

Peak solar-to-net electric efficiencies in the 16-18% range are achievable at the Kramer Junction SEGS plants

[6] These and other data cited in this section were provided in late 1995 by KJC Operating Company.



(Courtesy of KJC Operating Co. Also see Annex B, Cohen 1995)

Figure 4-6 Average Capacity Factor for the Kramer Junction Plants: 1989-1995

Figures

5. Status of Trough Technology

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5. Status of Trough Technology

Parabolic trough solar fields can supply steam to power plant systems, essentially fulfilling the role of a solar boiler in contrast to fossil fuel-fired boilers. The nature of the intermittent solar energy source is such that the maximum full load operating hours to be expected is about 2,400 hours annually. For this reason it makes good technical and economic sense to choose a power plant configuration that can run on fossil fuel for many additional hours in the year. Plants with the capability to run on solar energy and/or fossil fuel - called *hybrid* plants - are described in this section.

5.1 Parabolic Troughs Integrated with Steam Power Plants - the SEGS Technology

As discussed earlier, the Solar Electric Generating System (SEGS) is fundamentally a steam turbine power plant in which the main fuel is solar radiation. Figure 5-1 shows a schematic diagram of a typical plant configuration (the *optional* components are discussed a bit later). The development of the SEGS technology progressed rapidly during the design, construction and operation of the SEGS plants over the years 1984-1990, and continues today.

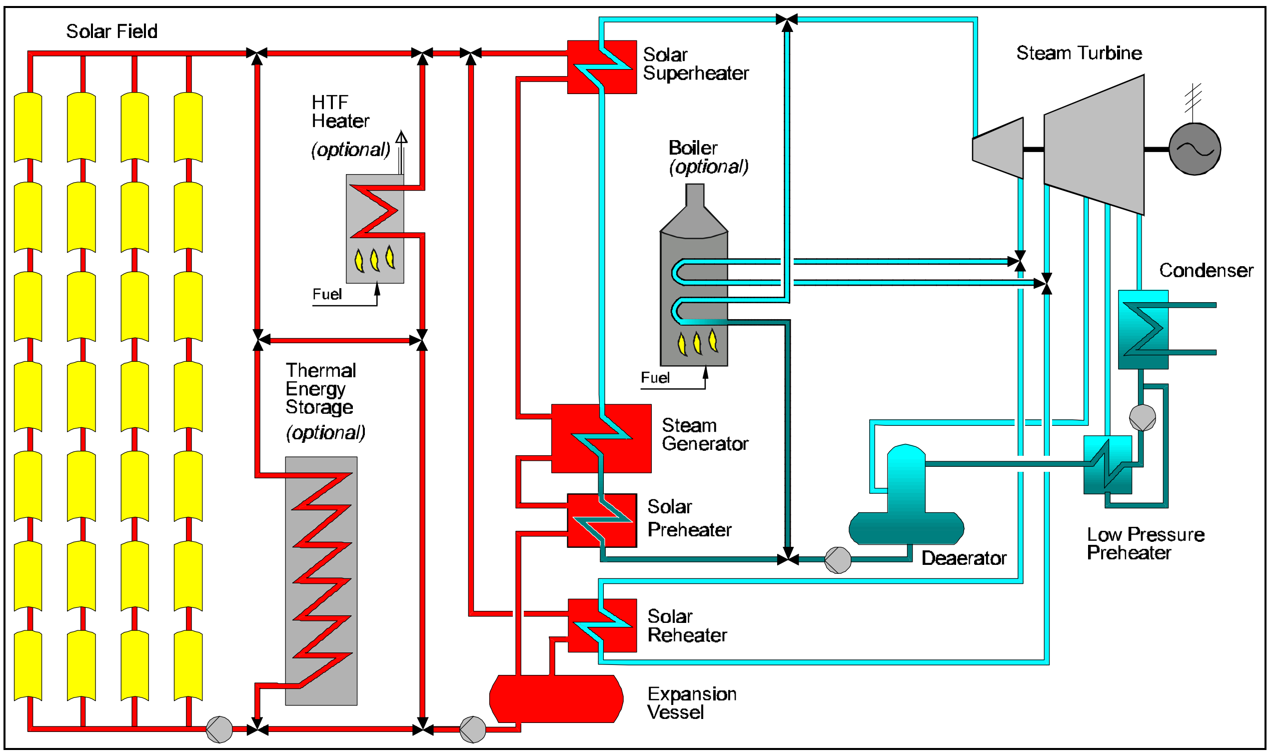

Figure 5-1 Integrated Solar/Rankine Cycle System (SEGS)

The solar field is comprised of parallel rows of Solar Collector Assemblies (SCAs). SCAs supply thermal energy to produce steam to drive a steam turbine/generator. The collectors are single-axis tracking and aligned on a north-south line, thus tracking the sun from east to west. An individual sun sensor device controls the position and tracking of each SCA. All of the SCAs are controlled by a main process computer, the Field Supervisory Controller (FSC).

The development of the SEGS technology progressed rapidly during the design, construction and operation of the SEGS plants over the years 1984-1990, and continues today

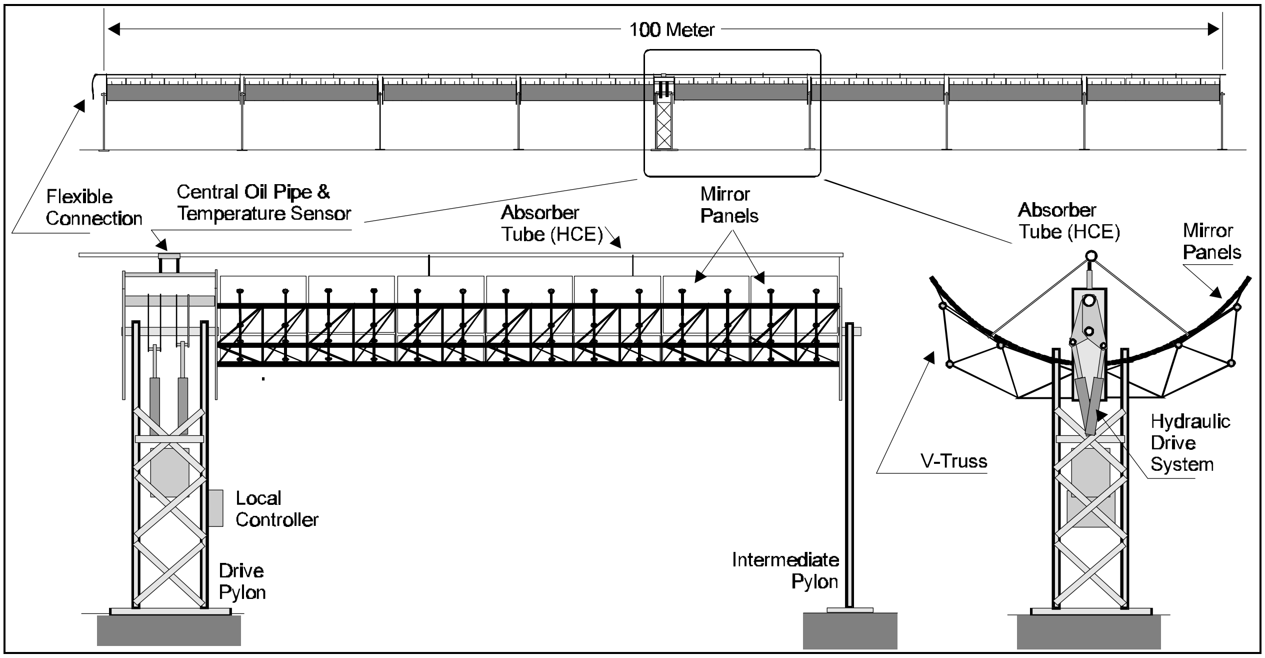

Figure 5-2 Schematic of a 3rd Generation Solar Collector Assembly.

Figure 5-2 shows the structure of an SCA, while a nearby photograph illustrates a focusing row of SCAs at a SEGS plant. Low-iron glass parabolic mirrors reflect the solar radiation to the absorber, or Heat Collection Element (HCE), with a concentration factor of about 80. The HCE, shown in Figure 5-3, is a coated, stainless-steel tube surrounded by an evacuated glass envelope - the selective coating on the inner tube enhances solar performance and is deposited by sputtering. The HCE also has bellows to allow differential expansion between the glass and steel. Getters are added to absorb gases such as hydrogen which permeate through the glass and stainless steel walls into the evacuated space.

In a parabolic trough solar field of current design heat is transported to the power block via an intermediate loop using a synthetic oil (biphenyl-diphenyl oxide) for the Heat Transfer Fluid (HTF). The HTF passes through a heat exchanger system to generate, superheat, and reheat the steam entirely with solar energy in the solar operating mode. Superheated steam generated by the heat-transfer fluid is then fed to a conventional steam turbine (a more efficient reheat turbine from SEGS VI on). Spent steam is condensed into water, which returns to the heat exchangers, where it reverts back to steam. After passing through the heat exchangers, the cooled heat-transfer fluid circulates once again through the solar field, thus repeating the process.

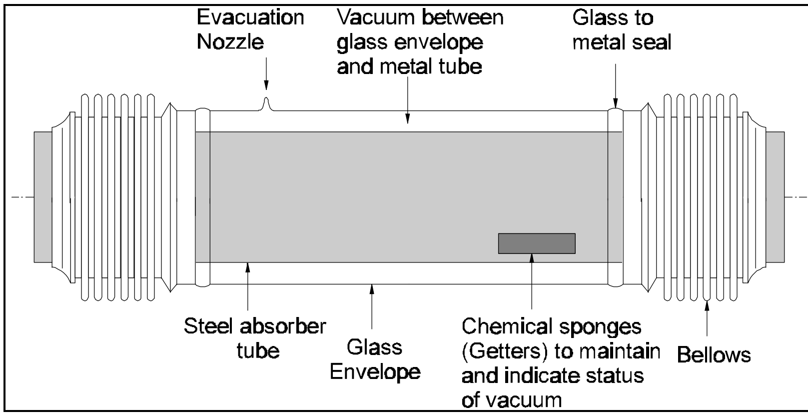

Figure 5-3 Schematic of a Heat Collection Element

The remainder of the plant equipment is conventional. A supplementary gas-fired boiler or heat transfer fluid heater is also available (both shown as options in Figure 5-1) to allow hybrid operation (solar and natural gas) on cloudy days or evenings. The conventional power block uses feedwater heaters to increase cycle efficiency for the inlet steam pressure and temperature conditions that are generated by the solar field. Solar field control is provided by microprocessors at each SCA linked to a central microcomputer; the power block is controlled by a distributed process control system. Auxiliary services include water pumping, treatment and storage, natural gas transmission, and electric interconnection and transmission.

5.2 Integration of Thermal Energy Storage

For sites where there is a moderate and consistent rise in electrical demand in early evening, an attractive design option is the use of thermal energy storage. Excess solar energy can be collected and stored during the day, and its utilization shifted to the evening to produce electricity. With a corresponding increase in the capacity of the solar field, thermal storage can also be used to increase the capacity factor of a solar power plant without the use of a fossil backup system where fuel is costly or its availability restricted. In either case, thermal storage improves the operation of a solar plant by buffering any rapid changes in solar radiation during the day. The integration of a thermal storage system into a SEGS configuration is shown as an option in Figure 5-1.

Solar thermal energy can be collected and stored for use at a later time

A large thermal storage system was installed in the SEGS I plant to supply 3 hours of full plant capacity, but thermal storage was not incorporated into the later SEGS plants. Where fossil backup is available, it is generally a more cost-effective option for extending the plant capacity factor and meeting demand requirements, though it increases plant emissions. Hence, thermal storage is more attractive from an environmental viewpoint and adds operating flexibility to a plant using solar energy alone as the heat source.

5.3 Parabolic Troughs Integrated with Other Power Plants

5.3.1 Combined Cycles

Conventional combined cycle (CC) power plants fired by natural gas are a very cost-effective configuration due to excellent performance, cost and emission characteristics.

The CC plant consists of a combustion (gas) turbine (GT), heat recovery steam generator (HRSG) and steam turbine (ST). Fuel is combusted in the gas turbine in the normal way, and the hot exhaust gases pass through the HRSG. Here the energy from the gases generates and superheats steam to be used in the ST bottoming cycle. Hence, the energy in the gas, or other fossil fuel, is used much more efficiently than in a GT alone. Modern cycles can achieve overall thermal-to-electric efficiencies of 55% or higher.

Parabolic troughs can be effectively integrated with a conventional combined cycle plant, as well as a steam cycle plant, for excellent performance and attractive emissions reductions

Solar energy from a parabolic trough solar field can be integrated with a CC in several ways to decrease the already low emissions. This is accomplished in an integrated solar-combined cycle system (ISCCS). Solar produced steam can be integrated either at high pressure into the heat recovery steam generator (HRSG) or at a lower pressure directly into the low pressure casing of the steam turbine. A schematic diagram showing both ISCCS configuration options is illustrated in Figure 5-4. In either configuration, the capacity of the steam turbine is increased over that in a conventional CC. If integrated into the HRSG (Option A), the solar steam would be supplied as saturated steam, and then superheated and reheated by the combustion turbine exhaust gases. Integration into the steam turbine directly (Option B) would normally be accomplished with lower pressure steam which is superheated by the solar field. Both approaches increase the thermal energy input which produces more electrical output. One objective of the integration is to achieve efficient operation even though solar energy input varies according to weather and time of day.

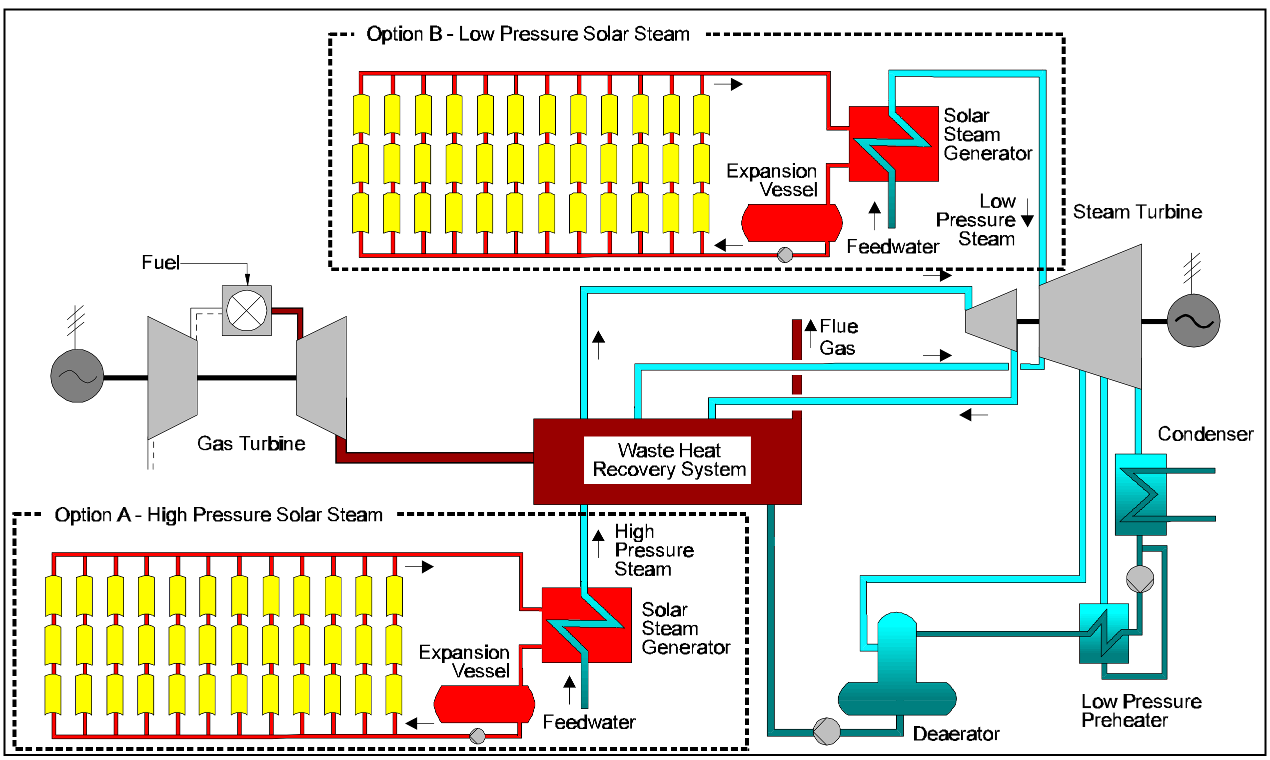

Figure 5-4 Integrated Solar/Combined Cycle System

An ISCCS plant offers good performance characteristics, attractive emissions reductions and a technically sound integration of a solar field with a combined cycle.

Moreover, the synergism of the combination is such that the efficiency of converting the solar parabolic trough thermal output to electricity can be up to 10% higher in an ISCCS plant than in a SEGS plant. Care must be taken in the system optimization to minimize the potential degradation of performance due to part-load operation of the bottoming cycle (steam turbine) when solar energy is not available.

An ISCCS plant would typically be run at high capacity factors where most of the energy input results from the combustion of the fossil fuel. At the *design point* of operation, the solar energy contributes 30-50% of the energy to the bottoming cycle and 20-30% to the combined cycle. On an *annual base-load basis* with a high capacity factors, solar energy contributes on the order of 10-20% to the bottoming cycle and 10% or lower to the combined cycle plant.

Integration of solar energy with a combustion turbine combined cycle can significantly increase the peak system capacity and system efficiency. An example using the Siemens/KWU V64.3 combustion turbine with integration into the HRSG compared to the simple combined cycle provides a good illustration of the results. The net ISCCS system capacity is 128 MW_e net compared to 92 MW_e net for a conventional CC. (Designs with integration of the solar steam directly into the low pressure turbine casing usually include a smaller solar contribution.) The *design* net heat rate is 4685 Btu/kWh (based on the fossil fuel input) compared to a standard combined cycle heat rate for this machine of 6540 Btu/kWh. This is equivalent to a fossil fuel based net system efficiency of 72.9% compared to 52.2%.

Peak thermal-to-electric efficiency based on fossil-fuel input can exceed 70% for an ISCCS plant compared to 50-55% for a conventional gas-fired combined cycle plant

The *annual* performance results for the same turbine at a 90% capacity factor show net fossil fuel based heat rates of 5875 Btu/kWh for the ISCCS and 6540 Btu/kWh for a simple combined cycle. This equates to an ISCCS efficiency of 58.8% compared to 52% for the simple CC.

5.3.2 Coal-Fired Steam Rankine Cycles

Solar steam can also be integrated into a base-load coal-fired Rankine cycle plant[1] somewhat analogous to the ISCCS concepts. For example, solar steam can be integrated in the lower pressure steam turbine casing, similar to option B shown for the combined cycle. High pressure solar steam can also be fed into the steam drum of the coal-fired boiler, where hot combustion gases would then provide high temperature superheat and reheat. An interesting aspect of integration into a coal fired plant is that solar steam would be displacing or supplementing steam which would be otherwise generated by firing coal, and the unit cost per unit of plant emissions reductions would be more significant than for the case of solar integration in a gas-fired combined cycle.

5.4 Solar Field and Balance-of-Plant Sourcing

The solar collector assembly illustrated in figure 5-2 is comprised of a number of components, most of which are conventional parts or sub-components available from

[1] Comments here based on preliminary analysis supplied by R. Dracker, Bechtel and G. Kolb, Sandia Natl. Labs in November, 1995

multiple sources. For the existing SEGS plants the assemblies making up the total 2,300,000 m^2 of solar fields were supplied from a broad mixture of companies and countries. Many steel parts of the metal structure, drive system, controls and other subsystems can be supplied by numerous vendors. In fact, these units make up about 60% of the total solar field direct costs. For any given project it is likely that local sources for steel structural elements will be in a preferred position. The parabolic reflectors and the HCEs have unique performance and manufacturing process characteristics which suggest that the know-how and manufacturing infrastructure of the current vendors of those components will be costly to duplicate by others, though this path is by no means out of the question.

FLAGSOL provided all the reflector mirrors for the existing SEGS plants and have continued to supply spare parts as required. SOLEL Solar Systems of Israel acquired the manufacturing facility and engineering data from Luz Industries Israel, and is prepared to manufacture HCEs as well as to offer a complete solar field using component suppliers similar to the Luz approach. In 1995 SOLEL supplied a large order of replacement HCEs to the Kramer Junction plants. Many other experienced vendors are similarly ready to reestablish their traditional solar field component supply, though it is likely that normal practice for competitive procurement would also result in new providers. Construction of the solar field will likely draw from local sources with installation procedures and quality control guided by the experience of the existing SEGS plants.

The HTF system consists of components widely used by the chemical and petroleum industries. The remaining systems of a solar power plant - SEGS or ISCCS - are conventional and offered widely. The market for power plants today is very competitive, leading to many sources for components at attractive costs. The integration between the solar field and power block, comprised of HTF-to-steam heat exchangers or heat recovery steam generators, serves a unique function but the equipment can be supplied by a number of leading vendors of such equipment.

A significant share of the solar field and power block equipment can be supplied from sources within the country of use, with specifics depending on the resources and capabilities of the country in question. Typical splits of local and foreign sourcing are quantified in section 6.

5.5 Further Parabolic Trough Developments

In an effort to further improve performance and reduce costs in the solar steam generation system, engineering development plans have been formulated for advances in collector design and the solar field system. Work is actively underway in Europe and the US. These plans take several paths.

First, a number of improvements to specific components or subsystems in the parabolic trough solar field of the oil-based SEGS system - the unique element in a solar plant - have been developed or envisaged. Advances include mirror washing techniques and mirror pad design, transportation methods, installation and replacement of both reflectors and receivers (heat collection elements), improved optical efficiency and new components e.g., rotating joints instead of flex hoses and redesign of the structural framework. The advanced oil-based system can be viewed as another evolutionary series of improvements to a well-tested technology. In addition, design improvements to lower costs and improve reliability in controls, the power block and balance-of-plant were identified. These included such items as improved mechanical seals on the HTF pumps, upgraded solar field and power block control systems, a single train of solar heat exchangers in contrast to dual trains, optimization of pump groups to reduce parasitics and lower capital costs, and optimization of foundation designs for major equipment.

Second, it was recognized that a dramatic reduction in plant heat rate was required for a solar plant which would operate in a mid- to base-load mode. To achieve this, conceptual designs were envisaged to utilize a parabolic trough solar field with a combined-cycle combustion turbine/steam turbine facility. Progress in this area has been described in the paragraphs above.

Third, a major change was conceived in which steam would be directly generated in the absorbing tubes of the HCE of the solar field (termed direct steam generation, or DSG). This latter approach has the advantage of eliminating the costly synthetic heat transport fluid, intermediate heat transport piping loop and solar-to-steam heat exchangers, as well as offering the potential of better turbine inlet steam conditions.

DSG systems will generate steam directly in the absorbing tubes of the collector field, eliminating the intermediate oil loop

Conversely, the concept introduces potential problems with two-phase flow instabilities in the solar field as the inlet feed water is converted into steam and superheated, and requires that the solar field piping operate at very high pressures (as high as 100-140 bar in contrast to 35 bar and below in the oil system). Thus, DSG introduces significant changes in the solar field concept, bringing with it the associated development and field-testing requirements of a major technological change. Figure 5-5 shows the evolution in the generations of the Luz parabolic trough collectors and the dimensions of the LS-4 conceptual design previously planned by Luz to be used in a DSG solar field. Many companies and institutions are working on DSG developments, including the Plataforma Solar de Almeria (Spain), DLR, ZSW, Siemens, FLAGSOL (all of Germany) and SOLEL Solar Systems (Israel).

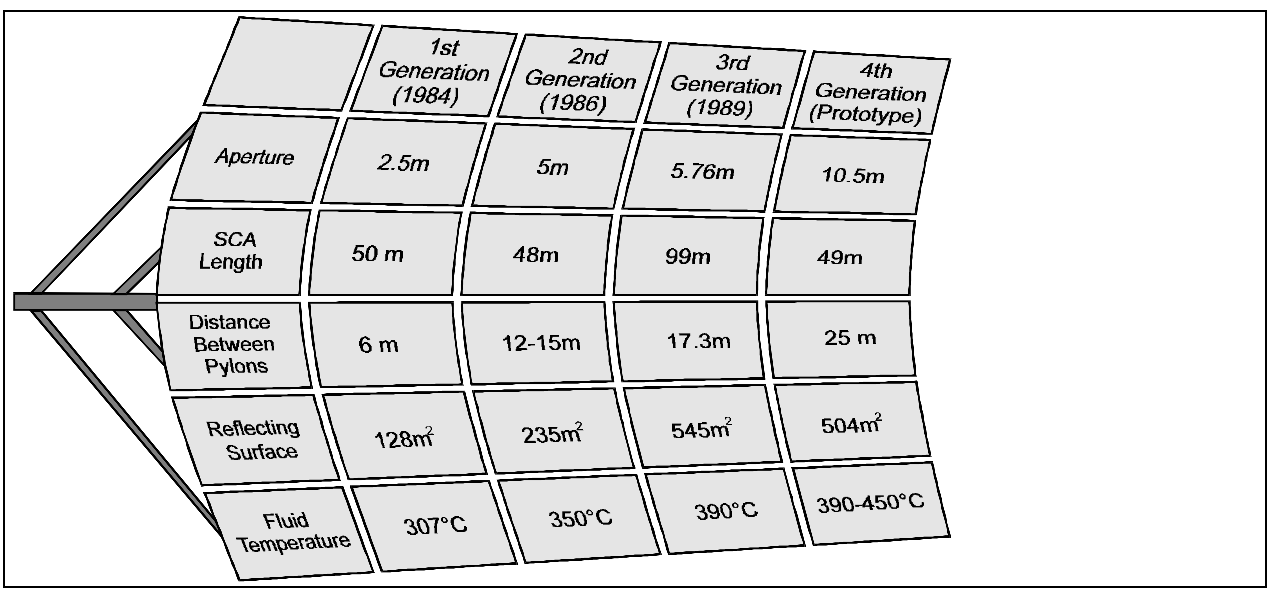

Figure 5-5 Evolution of Solar Collector Assemblies

In the US, ongoing technology improvements to parabolic troughs are taking place through a joint program between KJC Operating Company (SEGS III-VII) and Sandia National Laboratories-Albuquerque. The stated goal of the program is to seek ways to reduce operating and maintenance costs for future solar thermal electric plants; this is to be accomplished both by lowering direct costs for maintenance and by increasing the electrical output of the plants.

The O&M improvement program started in 1992 and is to continue through 1996. The technical tasks in the program are based on field experience, and include advancements in controls, maintenance practices, collector performance and equipment specifications.

Sandia and KJCOC in the USA are cooperating in a program to improve the operation and maintenance of solar thermal technology

This program is accomplishing impressive gains in various areas, such as the solar field control system, data acquisition and handling for performance and maintenance needs, solar field performance data, and plant maintenance planning methodologies. O&M costs are expected to be reduced from current levels by a factor of 1.5 or more in future plants which incorporate the findings of the program.

In Europe several projects have recently been inaugurated on parabolic trough systems including the experimental evaluation of direct steam generation, a comparison of costs between oil-based and direct steam solar fields and the development of design rules for large-scale grid-connected solar thermal plants. All of these studies are cost-shared between industry, government institutions and the European Union.

5.6 Potential Cost Reductions for Parabolic Trough Solar Steam Systems

The combination of technology improvements, economies inherent in larger-scale power units, mass production, mass procurement and market pressures are expected to lead to significant cost reductions in trough steam systems in a mature marketplace. Past evidence from SEGS I through SEGS IX showed a drop in levelized cost of electricity of about 50%. Based on subsequent experience in California, Cohen and Kearney[2] estimate 10% performance gains and 15% cost reductions in future SEGS-type plants based on known advances in current technology. As but a small example, the replacement of flexible hoses with ball joints in the solar field results in a cost reduction of about 10% for that component coupled with better reliability and reduced parasitic power losses. A recent European position paper[3] on solar thermal technology reviewed projected improvements in both current oil-based solar steam boilers and direct steam generation systems, as well as overall system enhancements, noting that up to a 30% reduction is possible. Section 7 of this report shows a 12% LEC cost reduction in a single installation from the economies of scale observed with a doubling of plant MW capacity.

While such gains based on developments in the technology itself are notable, there is no question that in a mature market, this and other solar thermal technologies will also

[2] G. Cohen and D. Kearney, "Improved Parabolic Trough Solar Electric Systems Based on the SEGS Experience", Proceedings of Annual Conf. of the American Solar Energy Society, SOLAR 94, June 1994.

[3] M. Becker (DLR), M. Macias and J. Ajona (CIEMAT-IER), Position Paper: Solar Thermal Power Stations, December 1995, prepared for presentation to EU Directorates.

see important cost reductions due to procurements of standardized materials and components in large quantities, solar field installation refinements, reduced engineering requirements, better integration of the solar steam system into the power plant, and the pressures of competitive supply. Economies of scale will result not only from larger single installations but also from the expanded production of solar systems for multiple plants. It is impossible to predict with any precision the eventual effects of all of these market forces. One relevant example is that recent experience with conventional gas-fired combined cycle plants, even as a mature technology, has shown system price reductions on the order 25% due to standardization of design and the pressures of international competition. Based strictly on our best judgment at this point in time, our estimate of potential cost-reduction factors is:

Improvement	Estimated Potential Cost Reduction, %
Oil-based Parabolic Trough System Design	10
DSG Parabolic Trough Design	5
Larger Single Plant Installations	10-15
Multiple-plant mass production/procurement	10-15
Standardized Engineering	5
Competitive Pressure	15-20
Overall Estimated Potential	45-55

5.7 Choosing the Appropriate Power Plant Configuration

Parabolic trough solar fields can be effectively integrated both technically and economically with steam Rankine cycles or with combined cycles. While the focus of the discussion here has been on new facilities, repowering of selected existing plants through the installation of a solar boiler to supply steam which replaces or supplements fuel-generated steam is possible and under active consideration. The primary purpose of the solar contribution is to avoid emissions from the use of fossil fuel. The cost of emissions reduction achieved by the use of solar steam is reduced, of course, if the fuel being displaced has high emissions per unit of generated electricity. Displacement of coal use is the best example of this point.

Evaluation of the costs of these plants shows that both types of plants are about equally effective with respect to emission avoidance costs. Therefore selection of the appropriate configuration for a given application becomes more an issue of fuel availability and operating scenario. If adequate natural gas is available and a combined cycle would be the natural choice for a purely fossil-fired plant, it will also be the choice for a solar/fossil-fuel integrated plant. Similarly, if fuel oil No. 2 or coal is the local fuel and a steam Rankine cycle plant is the best option, a SEGS-type plant would be chosen.

Figures

6. Project Implementation

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6. Typical Project Implementation Process

6.1 Project Development

The necessary tasks to develop solar thermal trough power plant projects are, of course, the same as for other large investment projects. The project development cycle comprises the pre-investment, investment and operational phases. Each of these three major phases is divisible into stages:

❑ Pre-investment phase
- Identification of investment opportunities (project ideas)
- Preliminary selection stage (prefeasibility study)
- Project formulation stage (techno-economic feasibility study)
- Evaluation and decision stage (evaluation report)

❑ Investment phase
- Negotiation and contracting stage
- Project design stage
- Construction stage
- Start-up stage

❑ Operational phase

A typical project development schedule for solar thermal trough power plant projects is shown in Figure 6-1. After a general evaluation of the relevant project information listed in Table 6-1, the first major development step is to arrange for partners and financing of a prefeasibility study.

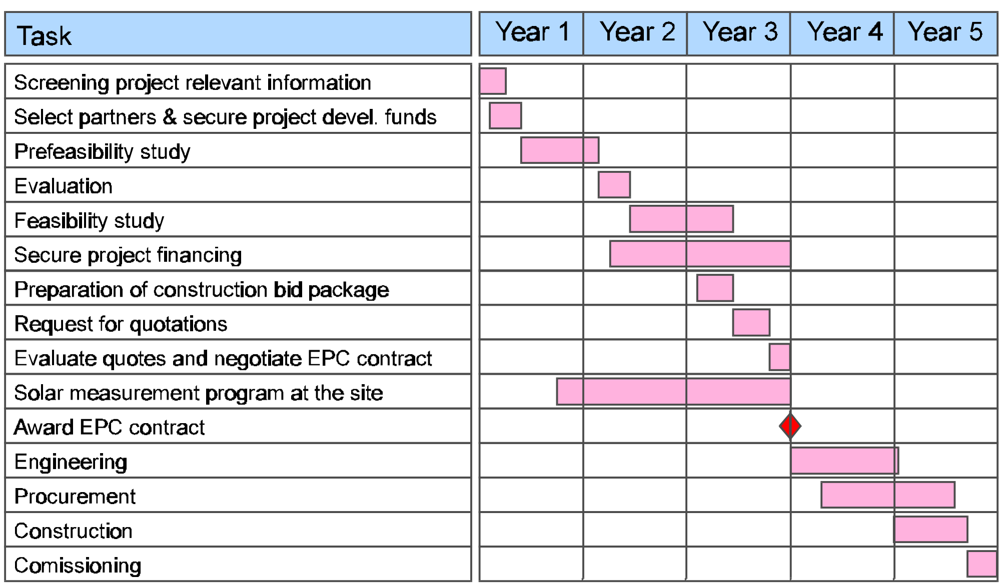

Figure 6-1 Typical Project Development Schedule

A prefeasibility study with a scope outlined in Table 6-2 seeks answers to the following key questions:

❑ What does it cost to produce a kWh of electricity at the desired location under certain operating conditions using the solar thermal trough technology?

❑ What are the environmental benefits of the project implementation, which might lead to investment grants or other subsidies?

❑ Power sector situation (market size, growth pattern, capacity requirements)
❑ Solar insolation level
❑ Appropriate sites
❑ Availability of project financing sources
❑ National policy issues

Table 6-1 Key Project Development Information

After a general evaluation of relevant project information the first major development step is to arrange for partners and financing of a prefeasibility study

❑ Preliminary conceptual design
❑ Location
❑ Performance under expected operating conditions and solar insolation
❑ Investment and O&M cost
❑ Levelized electricity cost and sensitivity analysis
❑ IRR based on a possible financing scheme
❑ Possible implementation structures (such as utility-owned or IPP)
❑ Legal and administrative requirements
❑ Environmental impact
❑ Other advantages of a solar thermal trough plant implementation

Table 6-2 Scope of the Prefeasibility Study

Covering the scope shown here, the prefeasibility analysis is typically carried out for several alternatives and a recommendation made on the most promising. The time frame is between 9 and 12 months, with the involvement of the local utility preferred from the onset.

If the results are promising, the launching of a feasibility study / project implementation evaluation will follow. Compared to a prefeasibility study, the follow-on assessment will focus on a single configuration and site and analyze all aspects in more detail. The conceptual design develops heat balances and top level specifications for all the major equipment, and the investment cost estimate is based on budgetary quotes from reputable vendors. The performance calculations for the solar field are based on insolation data which are verified with measured data from the site, with the plant performance developed using proven models and based on known equipment characteristics.

The time frame for these tasks is on the order of 12 to 15 months. The information developed forms the basis for a construction bid package and the related EPC (Engineering, Procurement and Construction) contract.

Financing can be expected to be more difficult for a project of this nature due to the fact that the higher investment and levelized electricity costs of solar plants must be viewed in the context of savings resulting from emission reductions, other environmental benefits, labor benefits and other factors. Thus the efforts to secure project financing, including negotiating the financing methods and parameters with relevant institutions, may be more time consuming than for conventional power projects.

6.2 Implementation Structure and Construction Schedule

A consortium bidding for the Engineering, Procurement and Construction Contract (EPC contract) for a solar thermal trough plant should ideally be composed of an experienced national construction company, a power block supplier, a solar boiler supplier and an architect/engineer with experience in thermal power station design and solar technology (see Fig. 6-2).

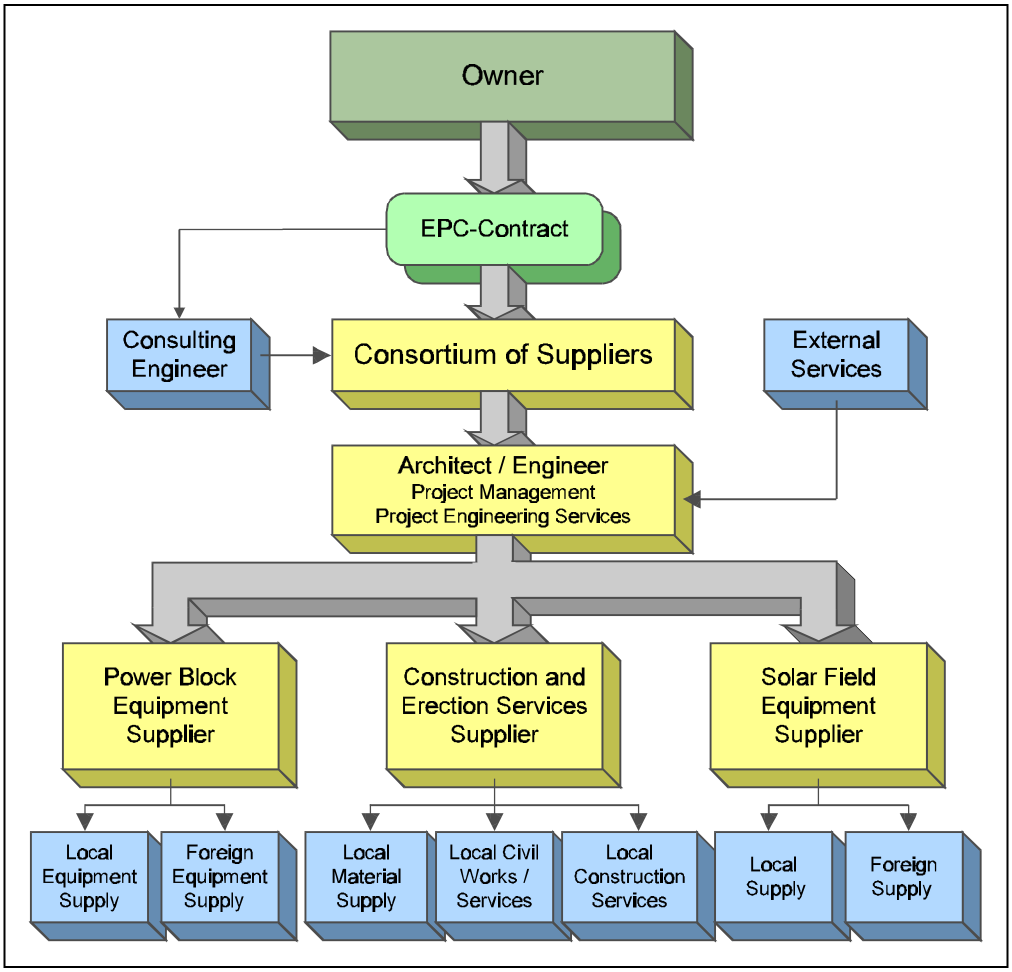

Figure 6-2 Sample Implementation Structure

A consortium bidding for an EPC contract should be composed of an experienced national construction company, a power block supplier, a solar boiler supplier and an architect/engineer with experience in thermal power station design and solar technology

A reasonable assumption for project implementation from the initiation of the EPC contract through to startup and acceptance is on the order of 24 months (roughly outlined in Fig. 6-3). After initial approvals are given, purchase orders and procurement of equipment can be initiated and initial on-site work can commence. The main lead item dictating the implementation schedule is the turbine generator, which requires about 18 months for supply and installation. The supply and installation of the other long-lead items, including the solar field, last no longer than 12 months. The period from ground breaking at the site to first synchronization to the grid is about 12 months.

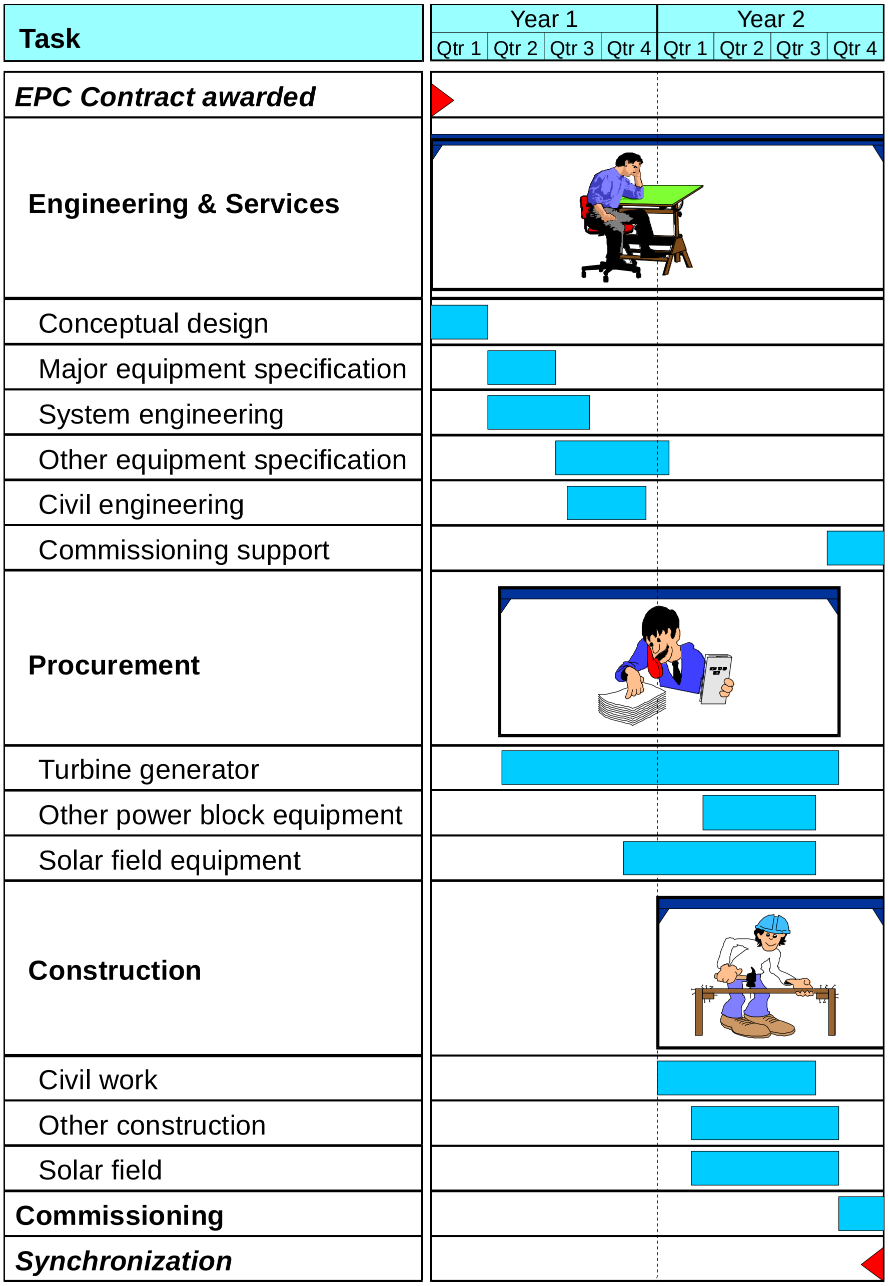

Figure 6-3 Implementation Schedule

6.3 Split of Supply

Two other points are of interest with respect to the implementation of a SEGS-type plant:

- ❑ How much of the scope is technology-specific, i.e., directly related to the solar energy equipment?
- ❑ How much of the investment could be spent within the host country of the project, and how much must be imported?

The following analysis shows that less than 20% of the EPC costs is attributable to key technology-specific solar field components. More than 80% are traceable to equipment and services that are available internationally from multiple sources. In fact, it is quite possible that about 40% to 50% of the EPC costs for labor, material and equipment can be supplied from within the project host country. This means that the higher up-front investment costs of this type of solar power plant will lead directly to_higher local employment during construction and plant operation rather than using valuable fossil fuel resources - often imported - in the future.

The higher up-front investment costs of this type of solar power plant will lead directly to higher local employment during construction and plant operation rather than using valuable fossil fuel resources - often imported - in the future

6.3.1 Conventional and 'Technology-Specific' Supply

A SEGS or an ISCCS plant consists of a conventional thermal plant (boiler, steam turbine generator and balance of plant, gas turbine, waste heat recovery system, steam turbine generator and balance of plant in the latter case) and of a solar boiler (solar field and heat transfer fluid system) as discussed in Chapter 5.

Less than 20% of the EPC costs are attributable to key technology-specific solar field components

Figure 6-4 illustrates the general investment cost split for a 135 MW_e ISCCS plant with a more detailed breakdown of the solar field machinery and equipment. The machinery and equipment for the solar field and the HTF system make up about 37% of the total EPC scope.

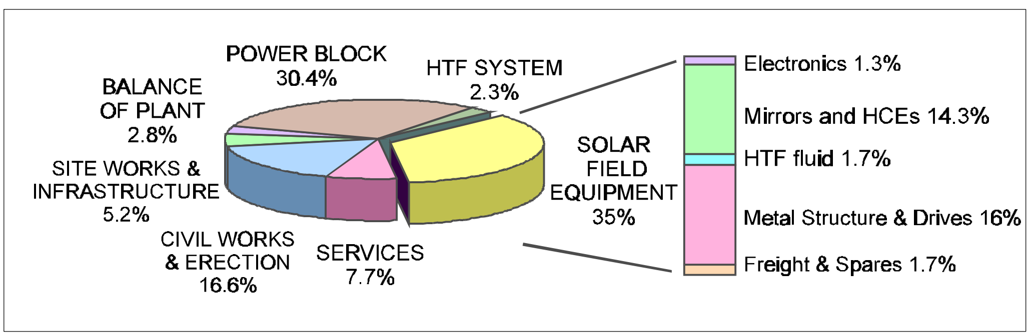

Figure 6-4 Investment Cost Split (135 MW_e ISCCS)

Examining in more detail the solar boiler related equipment, we find that only about 20% of the total EPC scope is technology-specific, consisting of:

- Heat collection (Heat Collection Elements and Reflectors)
- Solar field electronics
- HTF fluid (Heat Transfer Fluid, a synthetic oil)
- HTF vessels & heat exchangers (HTF/water-steam heat exchangers)
- HTF pumps

While all of the non-technology specific scope can be competitively bid on the worldwide market, it is also true that much of the technology-specific equipment is available from multiple sources worldwide. Equipment falling into this latter category includes, for example, the HTF vessels, piping, valves and pumps, solar field control systems, programmable controllers and many other items. The likely exceptions will be the heat collection elements and parabolic reflectors, which will have sole or limited suppliers. Other significant solar field cost items such as the structural steel, hydraulic drives and field installation do not require specialized knowledge.

6.3.2 Local and Foreign Supply

As an example, an estimate of the Moroccan supply share for a SEGS plant is given in Table 6-3 based on a recently published Technology Assessment Study and Prefeasibility Study sponsored by the European Union. It shows that the total domestic volume of scope for Morocco was estimated to be 41%. Studies carried out for different countries have typically resulted in a domestic volume of scope between 40% and 50% of the EPC cost for the first plant in that country. In the case of Brazil a domestic scope of 52% was achievable, as the generator and major parts of the other power block

The domestic volume of scope can be 40-50% of the EPC cost for the first plant in a country, and potentially increasing for future plants

equipment could be procured within Brazil. In general, infrastructure, civil works and erection can be assumed to be local scope of supply.

Plant Type	**SEGS**					
Solar Field(sq.m)	**470,880**					
Net Cap.(MW_e)	**80**					
Cooling Type	**Wet**					
Fuel Type	**Fuel Oil No.2**					
all amounts in ‘000 USD	Machinery & Equipment		Civil Works & Erection		TOTAL	
	Moroccan supply share	Total supply	Moroccan supply share	Total supply	Moroccan supply share	Total supply
SITE WORKS & INFRASTRUCTURE.			7,349	7,349	7,349	7,349
SOLAR FIELD	13,557	82,801	16,089	16,089	29,647	98,891
HTF SYSTEM	1,928	17,170	5,836	5,836	7,764	23,006
POWER BLOCK	3,589	31,666	7,509	8,224	11,098	39,890
BALANCE OF PLANT	16,046	32,093	14,907	14,907	30,953	47,000
SERVICES			6,950	15,109	6,950	15,109
TOTAL (EPC)	35,121	163,730	58,641	67,516	93,762	231,246
CONTINGENCIES					9,378	23,125
PROJECT TOTAL (7/95)					103,156	254,370
Moroccan share	21%		87%		**41%**	

Table 6-3 Cost Breakdown for a 80 MW_e SEGS Plant in Ouarzazate / Morocco

Figures

Tables

7. Economics of SEGS and ISSCS

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7. Economics of SEGS and ISCCS

A key figure used to characterize the economic viability of a power project is its levelized life-cycle cost, or Levelized Electricity Cost (LEC). The International Energy Agency (IEA) economic analysis methodology for renewable energy sources is used here to calculate the LEC.

A key figure used to characterize the economic viability of a power project is the Levelized Electricity Cost (LEC)

In general, levelized life-cycle cost is the present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments. By levelizing costs, resources with different lifetimes and generating capacities can be compared.

In power projects, the LEC is computed from three main cost parameters:

❑ cost of investment
❑ cost of Operating and Maintenance (O&M)
❑ cost of fuel

Using this approach, equivalent present-value costs of different technologies and configurations can be calculated and used as a basis for an economic decision. As long as renewable energy credits - such as tax credits or credits for emission reductions - are not established, the economics of a power plant are usually determined, in the final analysis, by the LEC. There is no question, however, that other socio-economic benefits are very important measures of the values of SEGS or ISCCS plants, and these are treated in section 8.

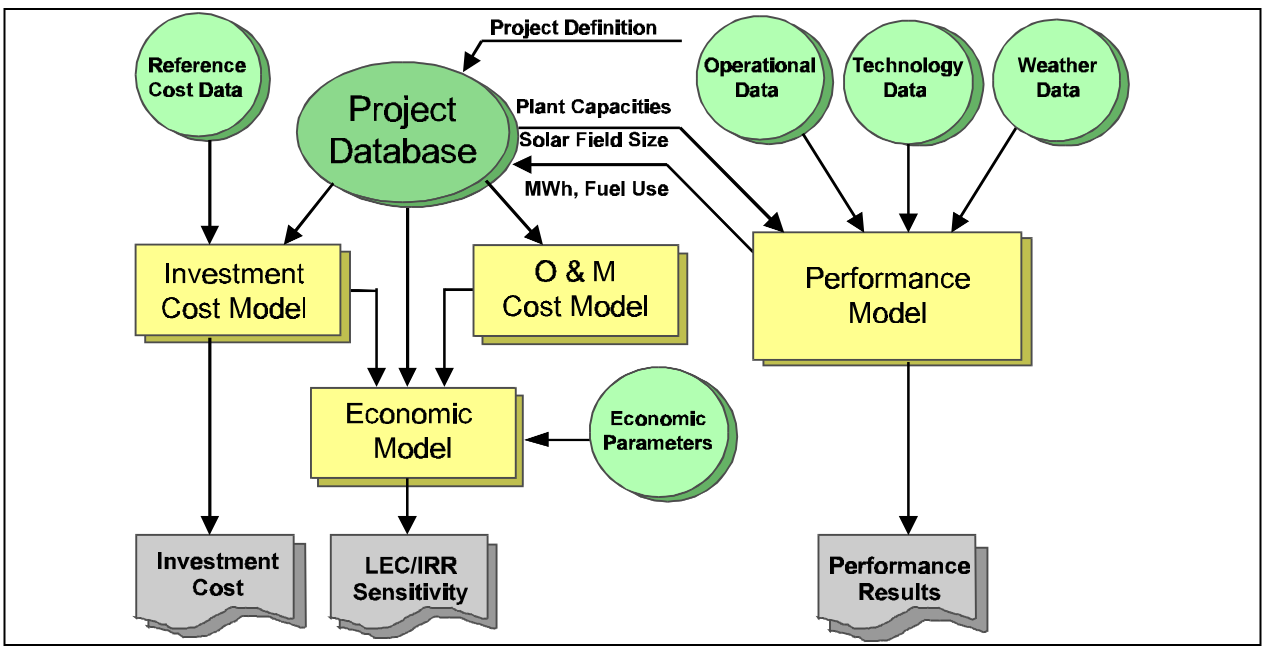

Figure 7-1 Methodology of Economic Evaluation

A number of performance and cost models feed information into the calculation of the LEC. Figure 7-1 depicts these calculation models and the flow of information between them. Briefly, the set of models are comprised of:

- ❑ The *performance model* to predict the electricity generation, fuel use and emissions based on plant capacity and design, location, weather data (solar radiation, temperature, wind) and operating strategy (see section 3).
- ❑ The *O&M model* to estimate the cost for operation and maintenance, taking plant capacity and design, operating modes and hours, and labor cost into consideration.
- ❑ The *investment cost model* to estimate capital costs based on costs from existing SEGS plants and budgetary quotes for major equipment, scaled to plant capacity and escalated over the time.
- ❑ Finally, the *economic model* to calculate the LEC using the output of other models and applying economic parameters such as expected lifetime and rates for depreciation, interest and inflation.

7.1 Investment Cost

Tables 7-1 to 7-3 show estimated investment costs for several SEGS and ISCCS plant configurations, as well as for two conventional fossil-fueled alternatives - a 52 MW Rankine-cycle plant and a 86 MW Combined Cycle. The cost evaluation is valid for July 1995.

While type of plant (SEGS or ISCCS) and capacity are the key variants, location, fuel type, cooling type, inclusion of thermal storage and solar radiation level also influence costs. One influence of the location is the country-specific labor rate structure which has a significant impact on the labor intensive solar field erection cost.

The cost estimates are broken down into the following groups:

- ❑ Site Works and Infrastructure
- ❑ Solar Field
- ❑ HTF System
- ❑ Power Block
- ❑ Balance of Plant
- ❑ Services

All the site land preparation (e.g., grubbing and grading), foundations, general site equipment, buildings and fencing are included in the site works and infrastructure. The major equipment systems have been categorized into the power block, solar field, and HTF systems, while the remaining auxiliary equipment (e.g., cooling tower or fire protection system) are included in the balance-of-plant. Services includes construction services, engineering services, project management services, site supervision, commissioning and start-up. Land costs and contingencies are added to complete the estimate.

A 80 MWe SEGS plant in standard configuration (natural gas fired backup system, wet cooling, no thermal storage) costs close to 2750 USD/kW

Table 7-1 compares investment costs of SEGS plants without thermal storage. The cost of an 80 MW_e SEGS plant in standard configuration (natural gas fired backup system, wet cooling, no thermal storage) is close to 2750 USD/kW. Comparison of this plant to the 40 MW_e and 160 MW_e capacities shows economy-of-scale savings on the order of 12% to 14% when doubling the capacity. The use of fuel oil No. 2 instead of natural gas will add 16% to the cost, mainly caused by the additional investment for flue gas treatment (desulfurization), fuel storage and handling. Utilization of dry cooling will add 10% to the cost of the conventional part of the plant.

Comparisons to conventional fossil-fuel plants are presented in Tables 7-2 and 7-3 for a 52 MW Rankine-cycle steam plant fired with fuel oil No. 2 and a 86 MW natural gas-fired Combined Cycle plant, respectively. Note that all direct and indirect costs are included in the estimates, and that almost 25% of the cost of the oil-fired steam plant stems from requirements for stack gas desulfurization, fuel storage and fuel handling.

Plant Location	**Nevada**	**Nevada**	**Nevada**	**Ouarzazate**	**Ouarzazate**
Plant Type	**SEGS**	**SEGS**	**SEGS**	**SEGS**	**SEGS**
Solar Field(sqm)	**235,440**	**470,880**	**928,680**	**470,880**	**470,880**
Net Cap.(MW)	**40.00**	**80.00**	**160.45**	**80.00**	**78.34**
Cooling Type	**Wet**	**Wet**	**Wet**	**Wet**	**Dry**
Fuel Type	**Nat. Gas**	**Nat. Gas**	**Nat. Gas**	**No.2**	**No.2**
SITE WORKS & INFRASTRUCTURE	6,020	7,733	11,433	8,678	8,069
SOLAR FIELD	53,219	101,091	182,093	101,091	101,091
HTF SYSTEM / BOILER	11,356	21,054	39,356	23,965	24,764
POWER BLOCK	23,414	38,037	61,569	38,037	37,885
BALANCE OF PLANT	10,708	17,395	28,158	47,092	56,296
SERVICES	8,803	14,301	23,075	14,301	14,273
LAND	258	498	966	0	0
CONTINGENCIES	11,352	19,961	34,568	23,316	24,238
PROJECT TOTAL	**125,130**	**220,071**	**381,219**	**256,481**	**266,618**
Unit Cost (USD/kW)	**3,128**	**2,751**	**2,376**	**3,206**	**3,403**
all amounts in '000 USD 07/95					

Table 7-1 Investment Cost of Different SEGS Plants

Table 7-2 also shows the cost impact of adding a thermal energy storage with a capacity of 3 full load hours plus additional solar field area to a SEGS plant, which may be desirable if fuel supply is uncertain or costly, or a high solar contribution to overall electricity production is preferred.

Plant Location	**Crete**	**Crete**	**Crete**
Plant Type	**Oil Steam**	**SEGS**	**SEGS**
Solar Field(sqm)	**0**	**297,570**	**395,670**
Net Cap.(MW)	**52**	**50**	**50**
Thermal Storage(MWhe)	**0**	**0**	**151**
Cooling Type	**Sea Water**	**Sea Water**	**Sea Water**
Fuel Type	**No.2**	**No.2**	**No.2**
SITE WORKS & INFRASTRUCTURE	4,275	6,342	7,061
SOLAR FIELD	0	66,262	86,258
HTF SYSTEM / BOILER	8,227	13,417	15,616
THERMAL ENERGY STORAGE	0	0	16,306
POWER BLOCK	20,838	27,436	27,436
BALANCE OF PLANT	31,905	31,905	31,905
SERVICES	6,197	10,344	13,674
LAND	191	3,475	4,586
CONTINGENCIES	7,144	15,571	19,826
PROJECT TOTAL	**78,777**	**174,752**	**222,668**
Unit Cost (USD/kW)	**1,507**	**3,511**	**4,431**
all amounts in '000 USD 07/95			

Table 7-2 Investment Cost of a SEGS Plant with and without Storage and a Comparable Rankine-Cycle Plant

This configuration increases the solar related capacity factor of the system by generating *additional* electricity during the evening demand peak. Were it desired only to shift the use of collected solar energy from daytime to evening it could be accomplished less expensively by adding only a thermal energy storage system without increasing solar field area.

The unit costs for ISCCS configurations (shown in Table 7-3) are in the range of 1,200 USD/kW to 1,700 USD/kW. The solar field and HTF system related unit costs are the same as in the SEGS plants, but relative to the overall plant capacity the solar field and, consequently the solar share of the net electric output, is much smaller. In SEGS plants the solar field size is linked to the steam turbine capacity, which is identical to the plant capacity. In ISCCS plants the solar field is designed to supply 30% to 60% of the energy needed for nominal steam turbine operation, which translates into 10% to 30% of the total plant capacity. The lower unit cost found in ISCCS, compared to SEGS, is based on the fact that an ISCCS is an integration of a combined cycle plant and a relatively small SEGS, which consists basically of the increased capacity of the steam turbine and the corresponding solar field.

Plant Location	**Huelva**	**Nevada**	**Mexico**	**Nevada**
Plant Type	**ISCCS**	**ISCCS**	**ISCCS**	**CC**
Solar Field(sqm)	**431,640**	**327,000**	**170,040**	**0**
Net Cap.(MW)	**137**	**135**	**128**	**86**
Cooling Type	**Sea Water**	**Wet**	**Wet**	**Wet**
Fuel Type	**Nat. Gas**	**Nat. Gas**	**Nat. Gas**	**Nat. Gas**
SITE WORKS & INFRASTRUCTURE	13,027	6,684	5,544	4,304
SOLAR FIELD	93,406	72,338	39,172	0
HTF SYSTEM / BOILER	6,755	6,360	5,967	0
POWER BLOCK	62,740	62,174	62,231	48,980
BALANCE OF PLANT	15,013	16,586	14,319	8,101
SERVICES	15,452	14,246	11,841	6,808
LAND	3,487	351	191	17
CONTINGENCIES	20,639	17,839	13,907	6,819
PROJECT TOTAL	**230,520**	**196,578**	**153,172**	**75,030**
Unit Cost (USD/kW)	**1,683**	**1,461**	**1,195**	**876**
all amounts in '000 USD 07/95				

Table 7-3 Investment Cost of ISCCS and Conventional Combined Cycle

7.2 Operation and Maintenance

In addition to capital costs, estimates of operation and maintenance costs are necessary for the calculation of the LEC. These costs include the elements of administration, operations, technical services, maintenance and reserve funds for overhauls and unexpected major equipment failures, and are based on actual O&M cost data provided by KJC OC[1]. The O&M costs for selected plants are listed in Tables 7-5 and 7-6. Distribution of O&M Costs by category and by element for different SEGS plants are given in Figure 7-2.

[1] KJC OC (Kramer Junction Company Operating Company) is the operator of the SEGS III to VII plants located at Kramer Junction, California USA

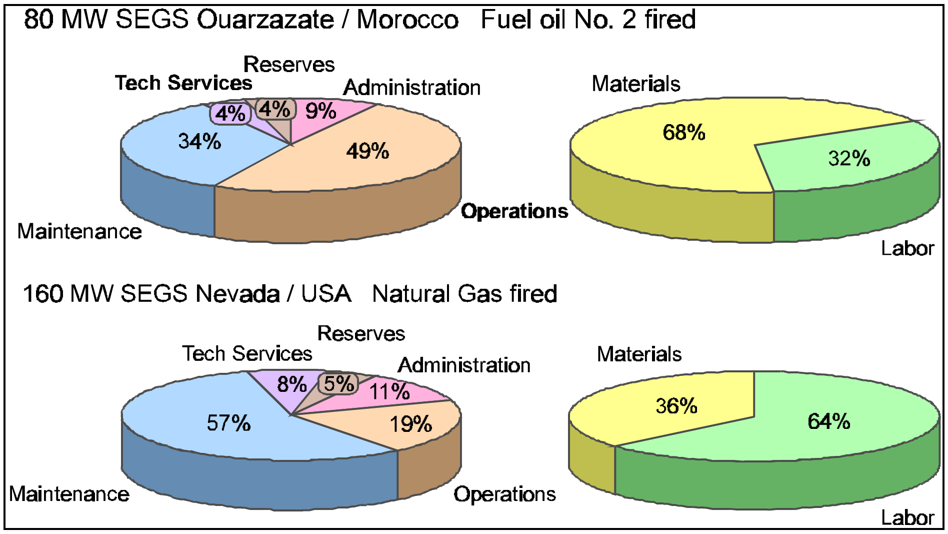

Figure 7-2 Distribution of O&M Costs by Category and by Element for Different SEGS Plants (Not including fuel)

The operating cost is higher for plants fired with fuel oil No. 2 due to the operating costs of the flue gas treatment system. The O&M cost elements with the highest dependency on the host country / site location are labor cost and water cost, which can strongly influence the split between labor and material costs as shown in Figure 7-2 for Morocco and the US.

7.3 Levelized Electricity Cost

The economic parameters used to calculate the LEC are listed in Table 7-4. Using different parameters will, of course, generate different results, but will not significantly affect the relative dependencies discussed below. For better understanding the cost per MWh of produced electricity is divided into capital-related, fuel-related and O&M-related shares. The LECs presented in Table 7-5 for six different SEGS plants and in Table 7-6 for three different ISSCS plants show a wide range of values, starting at 60 USD/MWh and increasing to 140 USD/MWh.

It is necessary to emphasize that LECs are highly dependent on:

- ❑ full load hours of operation per year, i.e., capacity factor
- ❑ solar share achieved under a given operating scenario
- ❑ fuel cost

The influence of these factors is so great that LECs given without this information would be meaningless to the reader.

Parameter	Value
Expected Lifetime (yr)	25
Annual depreciation rate	6.7%
Annual discount rate	8%
Annual insurance rate	1%
Annual income tax rate	0%

Table 7-4 LEC Parameters

The LEC values presented in the summary tables are given for a mid-load plant operation of approximately 4000 full load hours per year, i.e., for a capacity factor of about 46%. The significant impact of the full load hours is fully discussed in section

7.3.3. As explained in the technical sections, SEGS as well as ISCCS are a combination of a conventional thermal power plant and a solar field as another source of thermal energy. The solar share expresses the relative share of the total net electric output of a plant which is produced - emission free - by the solar resource. Considering today's fuel prices, thermal energy from fuel is cheaper than thermal energy collected and converted by any solar thermal technology. Therefore the higher the solar share, the higher is the LEC. In order to make comparisons between different hybrid solar thermal systems it is either necessary to compare them at operating conditions in which the 'solar content' is also comparable or to make a detailed analysis regarding the solar/fuel related LEC split as outlined in 7.3.3.

LEC values depend on factors such as plant configuration and capacity, annual operating hours, and fuel cost

7.3.1 LEC Dependence on Configuration and Location

Plant Location	**Nevada U.S.A.**	**Nevada U.S.A.**	**Nevada U.S.A.**	**Ouarzazate Morocco**	**Crete Greece**	**Crete Greece**	**Crete Greece**
Plant Type	**SEGS**	**SEGS**	**SEGS**	**SEGS**	**SEGS**	**SEGS**	**Oil Steam**
Insolation NDI (kWh/m²/yr)	**2694**	**2694**	**2694**	**2364**	**2293**	**2293**	**-**
Solar Field(sqm)	**235,440**	**470,880**	**928,680**	**470,880**	**297,570**	**395,670**	**0**
Net Cap.(MW)	**40**	**80**	**160**	**80**	**50**	**50**	**52**
Thermal Storage(MWhe)	**-**	**-**	**-**	**-**	**0**	**151**	**-**
Cooling Type	**Wet**	**Wet**	**Wet**	**Wet**	**Sea Water**	**Sea Water**	**Sea Water**
Fuel Type	**Nat. Gas**	**Nat. Gas**	**Nat. Gas**	**No.2**	**No.2**	**No.2**	**No.2**
Project cost ('000 USD)	130,387	228,611	395,071	265,021	180,901	229,020	92,786
Equivalent full load hours - total (h/yr)	4,256	4,238	4,266	4,114	4,254	3,989	4,001
Annual electric output (GW/yr)	170	339	685	329	212	200	209
Solar share	60%	60%	59%	53%	54%	70%	0%
Fuel cost (USD/ton or '000 m³)	81.70	81.70	81.70	250.06	155.70	155.70	155.70
Annual fuel cost	1,789	3,490	6,901	12,083	4,192	2,771	8,780
Annual O&M cost	3,464	4,764	6,587	3,942	2,820	2,861	2,598
LEC (USD/MWh)	107.05	91.64	77.44	129.49	118.68	143.25	93.46
Capital cost fraction	76.20	67.30	57.74	80.80	85.56	115.15	39.05
Fuel cost fraction	10.51	10.29	10.08	36.71	19.80	13.82	41.98
O&M cost fraction	20.34	14.05	9.62	11.98	13.32	14.27	12.42

Table 7-5 LEC Summary of SEGS and Rankine-cycle Plants

LECs for different configurations and locations are listed in Tables 7-5 and 7-6. Among the configurations are a conventional Combined Cycle plant as well as a Rankine cycle steam plant fired by fuel oil No. 2.

For SEGS plants the LECs range from 77.4 to 143.3 USD/MWh (solar share from 53 to 70%) and from 52.7 to 76.5 USD/MWh for ISCCS plants (solar share from 14 to 24%)

.

Plant Location	Mexico	Huelva Spain	Nevada U.S.A.	Nevada U.S.A.
Plant Type	**ISCCS**	**ISCCS**	**ISCCS**	**CC**
Insolation NDI (kWh/m²/yr)	**2694**	**2021**	**2694**	**-**
Solar Field(sqm)	**170,040**	**431,640**	**327,000**	**-**
Net Cap.(MW)	**128**	**137**	**135**	**86**
Cooling Type	**Wet**	**Sea Water**	**Wet**	**Wet**
Fuel Type	**Nat. Gas**	**Nat. Gas**	**Nat. Gas**	**Nat. Gas**
Project cost ('000 USD)	183,631	261,118	227,327	98,263
Equivalent full load hours - total (h/yr)	4,163	4,200	4,282	5,229
Annual electric output (GW/yr)	534	575	576	448
Solar share	14%	23%	24%	0%
Fuel cost (USD/ton or '000 m³)	81.70	165.74	81.70	81.70
Annual fuel cost	7,665	14,072	7,390	7,401
Annual O&M cost	4,606	5,991	6,190	3,704
LEC (USD/MWh)	52.74	76.41	58.94	42.15
Capital cost fraction	29.75	41.54	35.37	17.36
Fuel cost fraction	14.36	24.46	12.83	16.52
O&M cost fraction	8.63	10.41	10.74	8.27

Table 7-6 LEC Summary of ISCCS and conventional Combined Cycle Plants

We can observe from analyzing the LECs that:

- The economies of scale are significant (see section 7.3.2).
- Use of fuel oil No. 2 instead of natural gas, normally dictated by the site region, will increase the capital cost fraction and, even more significantly, the fuel cost fraction.
- Added solar share using thermal storage and a larger solar field will increase the capital fraction more than the fuel cost fraction will decrease. In this example, the solar share increases from 53% to 70%. Without thermal storage this could only be achieved by reducing full load hours. This in turn would increase the LEC of the system without storage to nearly the cost imposed by the configuration with storage (see section 7.3.4).

LECs and the solar share of ISCCS are in general lower than that of SEGS. The LEC of an ISCCS is always the average of a large portion of cost effective Combined Cycle generated electricity and a small portion of more expensive solar generated electricity. Observations on the solar/fuel related LEC split are discussed below in section 7.3.3.

7.3.2 Economies of Scale

Figure 7-3 illustrates the effect of changing plant capacity for a SEGS plant. The LEC cost of 107 USD/MWh for a 40 MW SEGS decreases by 28% to 77.4 USD/MWh for a 160 MW SEGS. The first step of 100% in capacity increase yields an LEC reduction of 14.5%, and the second step a reduction of 15.5%. The unit investment costs are reduced by 12% for each 100% capacity increase step.

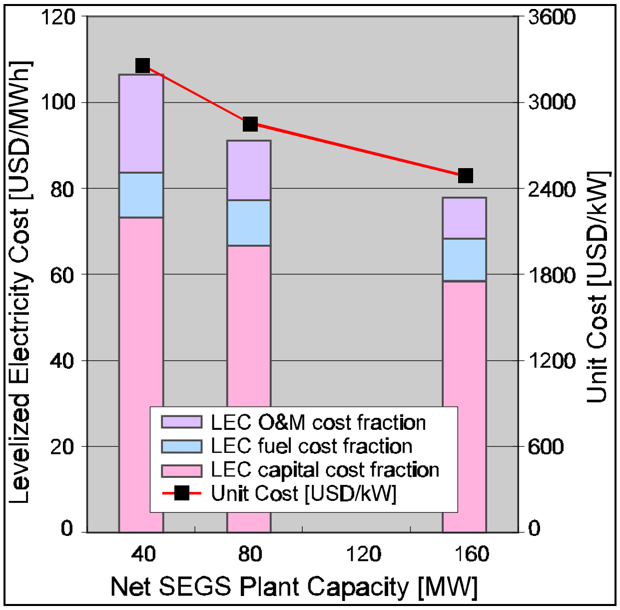

Figure 7-3 Economy of Scale (SEGS)

7.3.3 Influence of Full Load Hours on LEC

The significant dependency of the LEC on the annual full-load hours is illustrated in Figure 7-4. The decrease in LEC with increased plant operation stems from several effects. As with any power plant, for increased operation the same capital costs are spread over more hours and the O&M increase is less then linear. Moreover, beyond the approximately 2,000 to 2,400 hours attributable to solar energy the additional costs to include and operate the fuel-based portion of the plant come less expensively.

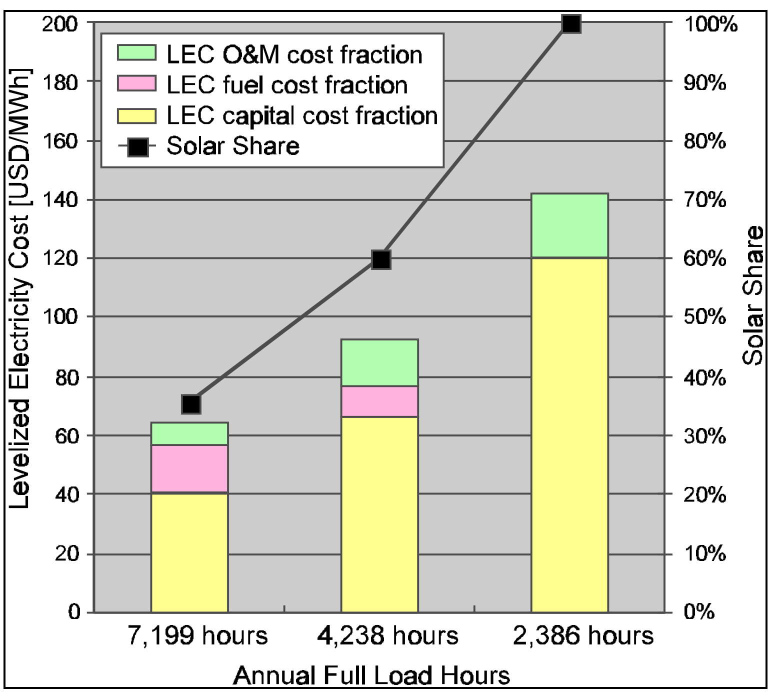

Figure 7-4 LEC Depending on Annual Full Load Hours (SEGS/Nevada)

7.3.4 Thermal Storage Impact on LEC

The performance data used in Table 7-7 are obtained, as in all the tables used in this section, from the FLAGSOL Performance Model. This model simulates the operation of the plant such that a given demand profile is satisfied as closely as possible, considering constraints such as start-up, minimal and maximum loads and flow rates.

Plant Location	**Crete / Greece**			**Crete / Greece**			
Plant Type	**SEGS**			**SEGS**			
Solar Field(sqm)	**395,670**			**297,570**			
Net Cap.(MW)	**50**			**50**			
Thermal Storage (MWhe)	**151**			**0**			
Cooling Type	**Sea Water**			**Sea Water**			
Fuel Type	**No.2**			**No.2**			
Project cost ('000 USD)	229,020			180,901			
Equivalent full load hours - total (h/yr)	7,004	3,989	2,725	7,332	4,254	3,055	2,124
Solar share	41%	70%	100%	32%	54%	70%	100%
Fuel cost (USD/ton or '000 m³)	155.70						
Annual fuel cost	9,271	2,771	0	10,602	4,192	2,111	0
Annual O&M cost	3,667	2,861	2,444	3,561	2,820	2,542	2,211
LEC (USD/MWh)	102.34	143.25	186.43	88.45	118.68	142.60	192.29
Capital cost fraction	65.58	115.15	168.59	49.64	85.56	113.46	171.37
Fuel cost fraction	26.34	13.82	0.00	29.05	19.80	13.22	0.00
O&M cost fraction	10.42	14.27	17.85	9.76	13.32	15.92	20.91

Table 7-7 LEC Summary (SEGS storage / No storage)

The LEC of a system that replaces up to 3 full load hours per day of fuel use by utilization of stored thermal energy is approximately 20% higher; however, the solar share rises from 54% to 70% (at 4000 full-load hours). Looking at operating conditions where the solar share is the same in the two systems, the difference in the LECs is quite low for solar shares below 60% and above 85% the system with storage yields even lower LECs. Figure 7-5 illustrates these dependencies.

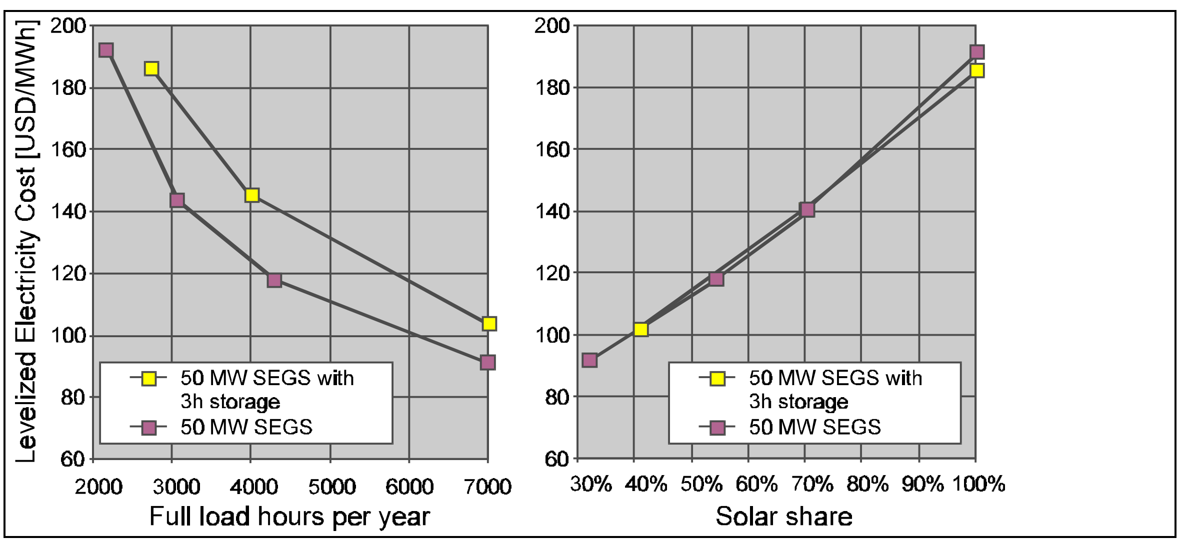

Figure 7-5 Thermal Storage Impact on LECs

7.3.5 Solar/Fuel Related LEC Split

The calculated LEC is the <u>average</u> LEC over the different operating modes (solar only, fuel only, hybrid) of a plant as it is dispatched to satisfy a certain demand profile. When discussing hybrid solar plants, questions arise concerning comparative costs between “solar-generated” and “fuel-generated” electricity. For current fuel prices it can be observed that it is less expensive to produce power by fossil-fuel than by solar energy, and thus the average kWh cost of the hybrid system does not reflect the ‘real’ generation cost of the solar system. This raises the question:

“What does a solar-produced kWh cost?”

This question is not easily answered for a hybrid plant in which the solar-fuel operation and equipment are tightly integrated. As an example, the straightforward approach of determining the cost of a solar-produced kWh in a SEGS plant by calculating the LECs of pure solar operation does not lead to the correct answer. This is so because the procedure would incorrectly charge part of the cost of purely fuel related equipment as well as fuel-related O&M cost provisions to the solar kWh. For this discussion, the approach described in the box ‘Calculation of the Solar/Fuel Related LEC Split‘ is used to calculate the solar-related LEC and the fuel-related LEC for SEGS as well as for ISCCS. It is essentially a calculation of the LEC split based on an allocation to solar operation and to fuel operation of both the energy produced and the costs for investment, O&M and fuel.

The real cost of solar-generated electricity can be found by a separate calculation of the solar related and the fuel related LEC

Another aspect with respect to the cost of “solar-generated” and “fuel-generated” electricity is the fact that the cost of the former (solar) is fixed and not subject to inflation or availability problems, unlike the cost of the latter (fuel). Thus the investment in the solar boiler is a hedge against the risk of insufficient fuel availability.

Plant	Fuel Price	Grant			Levelized electricity cost (USD/MWh)		
	USD/MMBtu	'000 USD	% of Project	% of Solar boiler	Fuel related	Solar related	Average
135 MW ISCCS	Nat. Gas	no grant			44.81	104.94	58.94
4,282 Full load hours	2.35	45,298	23%	50%	44.81	70.26	50.79
24 % Solar share		78,544	40%	87%	44.81	44.81	44.81
138,737 "solar" MWh/yr		no grant			60.44	104.94	70.90
	4.54	45,298	23%	50%	60.44	70.26	62.75
		58,133	30%	64%	60.44	60.44	60.44
	10.78	no grant			104.94	104.94	104.94
80 MW SEGS	Nat. Gas	no grant			62.74	110.84	91.64
4,237 Full load hours	2.35	60,123	27%	50%	62.74	80.24	73.26
60 % solar share		91,763	42%	79%	62.74	62.74	62.74
203,376 "solar" MWh/yr		no grant			86.73	110.84	101.22
	4.54	60,123	27%	50%	86.73	80.24	82.83
		47,381	22%	39%	86.73	86.73	86.73
	6.73	no grant			110.84	110.84	110.84
50 MW SEGS	Fuel Oil	no grant			96.62	137.34	118.68
4,254 Full load hours	4.02	39,501	23%	50%	96.62	101.64	99.34
54 % solar share		45,059	26%	57%	96.62	96.62	96.62
114,858 "solar" MWh/yr	7.81	no grant			137.34	137.34	137.34

Table 7-8 Solar/Fuel Related LEC Split

Using this methodology, Table 7-8 lists the average LEC, the solar related LEC and the fuel related LEC for different plant configurations under varying assumptions of fuel costs and grants for the solar boiler.

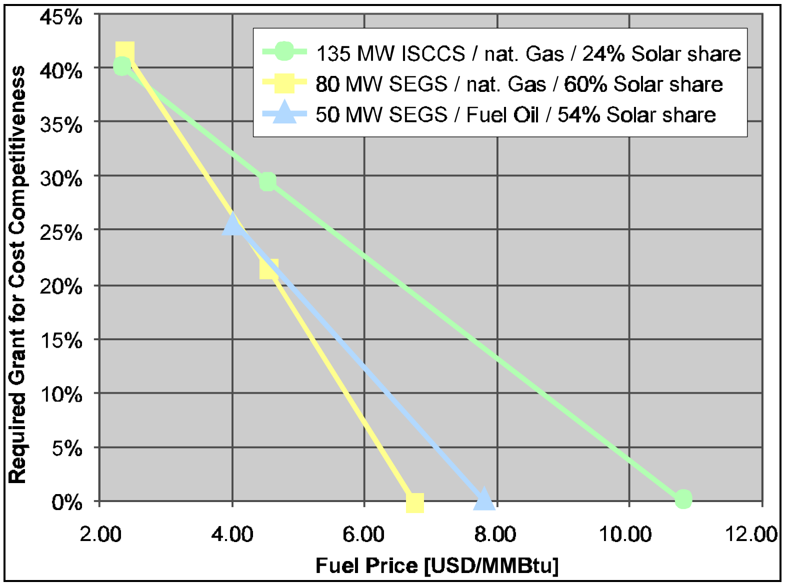

Figure 7-6 Fuel Price Required for Cost Competitiveness

The difference in cost for the 'solar' kWh between an ISCCS and a SEGS (both gas fired) is quite small. The average LECs of a gas fired ISCCS are about 35% lower than a gas fired SEGS. The split shows that 30% stems from the better utilization of the fuel by the combined cycle process and less than 5% from the better utilization of thermal energy from the solar field. The latter gain occurs because the bottoming cycle in the ISCCS is more efficient than in a SEGS plant. There are also proposed ways to integrate solar with a combined cycle which are less efficient than a SEGS plant and would see no advantage in this regard.

LECs are presented for projects without a grant and with a 50% grant for the solar boiler; in addition, the level of grant is calculated which results in equivalent costs for the solar based and fuel based kWh's. In these examples the required grants for the solar boiler range from 39% to 87%, or from 22% to 42% for the plant.

For reference, the lower gas price holds for the US, the higher gas price characterizes Spain, and the fuel oil price is valid for Greece (all fuel prices as of January 1995). The fuel price at which no grant is necessary for cost competitiveness is given in the last row of Table 7-8 and in Figure 7-6.

[LAYOUT: Separate box!]

Calculation of the Solar/Fuel Related LEC Split

The following approach was taken to calculate the solar-related LEC and the fuel-related LEC for SEGS as well as for ISCCS:

- ❑ Investment costs are divided into three categories: related to fuel operation only, related to solar operation only, and shared by both solar and fuel operation.
- ❑ Full load hours considered in the calculations are based on a split according to the fuel and solar shares calculated in the performance runs.
- ❑ LECs are then calculated separately for the fuel and the solar related parts.

To allocate the cost elements, the following guidelines were applied:

- ❑ SEGS type plant:
  - Shared part: Power block; most of balance of plant; infrastructure
  - Fuel part: Boiler or HTF heater; flue gas desulfurization; fuel handling
  - Solar part: Solar field; HTF system
- ❑ ISCCS type plant:
  - Shared part: Infrastructure; some balance of plant
  - Fuel part: Gas turbine and waste heat recovery system; cost of a steam turbine sized as in a conventional combined cycle plant; fuel handling
  - Solar part: Cost of increasing the steam turbine capacity; solar field; HTF system
- ❑ The shared part of the system is split in proportion to the total fuel/solar full load operating hours.
- ❑ In a SEGS type hybrid plant, there is the need for a ‘lost utilization balance’ (see Table 7-9). This number gives a credit to the fuel operating mode in order to compensate for the lost operating hours that are replaced by the solar boiler. The annuity for the fuel related investment is calculated twice: once under the assumption that there is no solar boiler and once for the remaining fuel operating hours. The fuel related LEC is then credited with the difference and solar LEC charged accordingly.
- ❑ Fuel costs are fully allocated to the fuel related part.
- ❑ The O&M costs were examined for costs which are attributable to the presence of a solar field, and split accordingly.

Table 7-9 shows the detailed results when applying the method above to an ISSCS and SEGS plant.

Plant Location	Nevada			Nevada		
Plant Type	**ISCCS**			**SEGS**		
Insolation NDI (kWh/m²/yr)	**2694**			**2694**		
Solar Field(sqm)	**327,000**			**470,880**		
Net Cap.(MW)	**135**			**80**		
Cooling Type	**Wet**			**Wet**		
Fuel Type	**Nat. Gas**			**Nat. Gas**		
Operating mode	Fuel related	Solar related	Total	Fuel related	Solar related	Total
Equivalent full load hours (h/yr)	3,276	1,006	4,282	1,691	2,547	4,238
Solar share	0%	100%	24%	0%	100%	60%
Fuel used ('000 m³/yr)	90,456	0	90,456	42,713	0	42,713
Annual fuel cost	7,390	0	7,390	3,490	0	3,490
Annual O&M cost	3,814	2,377	6,190	1,383	3,382	4,764
Project cost fraction	72,272	111,030	183,301	12,064	132,669	144,733
Distributed shared fraction	10,156	3,121	13,277	30,064	45,273	75,337
Total related cost fraction	82,428	114,150	196,578	42,129	177,942	220,071
Annuity per MWhe	19.39	87.39	35.37	32.28	90.55	67.30
Lost utilization balance	0.00	0.00	0	-5.56	3.69	0
LEC / no Grant (USD/MWh)	**44.81**	**104.94**	**58.94**	**62.74**	**110.84**	**91.64**
Capital cost fraction	19.39	87.39	35.37	26.73	94.24	67.30
Fuel cost fraction	16.77	0.00	12.83	25.79	0.00	10.29
O&M cost fraction	8.65	17.55	10.74	10.22	16.60	14.05
Grant as % of project cost	23%			27%		
Grant as % of solar boiler cost	50%			50%		
Solar Boiler cost	90,596			120,246		
Grant for solar boiler	0	45,298	45,298	0	60,123	60,123
Total cost fraction after grant	82,428	68,852	151,280	42,129	117,819	159,948
Annuity per MWhe	19.39	52.71	27.22	32.28	59.96	48.91
Lost utilization balance	0.00	0.00	0	-5.56	3.69	0
LEC / with Grant (USD/MWh)	**44.81**	**70.26**	**50.79**	**62.74**	**80.24**	**73.26**
Capital cost fraction	19.39	52.71	27.22	26.73	63.65	48.91
Fuel cost fraction	16.77	0.00	12.83	25.79	0.00	10.29
O&M cost fraction	8.65	17.55	10.74	10.22	16.60	14.05
all amounts in '000 USD 07/95						

Table 7-9 Solar/Fuel Related LEC Split (SEGS, ISCCS)

In locations where natural gas is not available, fuel oil No. 2 fired Rankine cycles (Oil/Steam Plants) are the thermal power plant alternatives to a SEGS plant, as reliable economic operation of a combined cycle is not achievable with low quality fuel.

Table 7-10 summarizes the solar-fuel cost split analysis for fuel oil No. 2 fired oil steam and SEGS plants. All plants are equipped with state of the art flue gas desulfurization and emission controls. Using a different (lower) project cost for the Oil/Steam Plant will not change the results, as the same reduction would need to be applied to the SEGS plants, which are the combination of an Oil/Steam Plant and a solar boiler. The close agreement in the fuel-related LEC (without grants) for the Oil Steam plant compared to the SEGS plant attests to the reasonableness of the method used to allocate the costs.

Plant Location	Crete	Crete		
Plant Type	**Oil Steam**	**SEGS**		
Insolation NDI (kWh/m²/yr)	**1812**	**2293**		
Solar Field(sqm)	**-**	**297,570**		
Net Cap.(MW)	**52**	**50**		
Thermal Storage (MWhe)	**0**	**0**		
Cooling Type	**Sea Water**	**Sea Water**		
Fuel Type	**No.2**	**No.2**		
Operating mode	Fuel related	Fuel related	Solar related	Total
Equivalent full load hours (h/yr)	4,001	1,949	2,305	4,254
Solar share	0%	0%	100%	54%
Fuel used (tons/yr)	56,392	26,925	0	26,925
Annual fuel cost	8,780	4,192	0	4,192
Annual O&M cost	2,598	1,141	1,679	2,820
Project cost fraction	78,777	29,647	89,683	119,330
Distributed shared fraction		25,397	30,025	55,422
Total related cost fraction		55,044	119,708	174,752
Annuity per MWhe	39.05	58.81	108.19	85.56
Lost utilization balance	0	-17.16	14.52	0
LEC / no Grant (USD/MWh)	**93.46**	**96.62**	**137.34**	**118.68**
Capital cost fraction	39.05	41.65	122.70	85.56
Fuel cost fraction	41.98	43.20	0.00	19.80
O&M cost fraction	12.42	11.76	14.64	13.32
Grant as % of project cost		23%		
Grant as % of solar boiler cost		50%		
Solar Boiler cost		79,003		
Grant for solar boiler		0	39,501	39,501
Total cost fraction after grant		55,044	80,207	135,251
Annuity per MWhe		58.81	72.49	66.22
Lost utilization balance		-17.16	14.52	0
LEC / with Grant (USD/MWh)		**96.62**	**101.64**	**99.34**
Capital cost fraction		41.65	87.00	66.22
Fuel cost fraction		43.20	0.00	19.80
O&M cost fraction		11.76	14.64	13.32
all amounts in '000 USD 07/95				

Table 7-10 Solar/Fuel Related LEC Split (Oil/Steam, SEGS, SEGS with Storage)

The fuel cost of 155.7 USD per ton is equivalent to 4.02 USD/MMBtu. A grant of 52% or 41,622 MUSD on the solar boiler enables a 50 MW SEGS plant to produce electricity at the same cost as an Oil/Steam Plant, but 54% of the energy is produced free of emissions.

Figures

Tables