4. EVALUATION OF POTENTIAL FOR COST REDUCTIONS — TROUGH

4.1 DEVELOPMENT PLAN FOR COST REDUCTION

The SunLab trough model *DueDiligence11–Excelergy11-14-01.xls* (SunLab 2001) depicts the industry plan for long-term cost reduction. The industry plan keys on thermal storage to obtain a high capacity factor, which reduces the O&M costs ($/MWh) by obtaining a higher annual MWh generation. In combination with thermal storage, increased annual net efficiency, and reduced equipment cost via technology advancements, competition and deployment are primary elements in reducing the long-term capital costs of the trough plant.

The parabolic trough industry has developed a proprietary plan to lower costs, emphasizing the near-term, which cannot be shared in detail since it would compromise their ability to compete in the domestic and international market. However, the SunLab model provides a cost estimate that closely follows the industry expectations for research and development advances in component and subsystem improvements. Whereas the SunLab plan for plant implementation assumes, for comparative purposes, the use of thermal storage starting in 2004, the U.S. trough industry is pursuing a commercialization plan that favors implementation of SEGS-type plants in the near-term. With this plan, industry has set cost goals that target a solar field cost less than $200/m^2 and an installed plant cost in the 2,000–2,400 $/kW range by 2006. The industry considers this plan a low-risk approach, with plants similar to the existing SEGS type plants able to produce electricity in a hybrid model. By incorporating this hybrid option, the only increase to the solar-only portion of the project is the relatively small capital cost of a boiler cost of fuel and fuel costs during hybrid operation. Near-term development of this plan is shown below in Table 4-1.

Table 4-1 — Near-Term Development for Trough Industry

Case*	Baseline	Trough Industry Near Term		
Project	SEGS VI Hybrid	Trough 50 Hybrid (US)	Trough 50 TES (Spain)	Trough 40 ISCCS (GEF)
In Service	1989	2004	2004	2004
Net Power (MWe)	30	50	50	40
Capacity Factor (%)	22/34% **	29/40% **	47%	28%
Solar Field (km^2)	0.188	0.312	0.496	0.184
Heat Transfer Fluid	VP-1	VP-1	VP-1	VP-1

Case*	Baseline	Trough Industry Near Term		
Project	**SEGS VI Hybrid**	**Trough 50 Hybrid (US)**	**Trough 50 TES (Spain)**	**Trough 40 ISCCS (GEF)**
In Service	**1989**	**2004**	**2004**	**2004**
SF Operating Temperature (°C)	391	391	391	391
Thermal Storage (hrs)	0	0	9	0
Thermal Energy Storage	NA	NA	Indirect 2-Tank	NA
Thermal Storage Fluid	NA	NA	Solar Salt	NA
Land Area (km^2)	0.635	1.052	1.675	0.623
Comment	Hybrid backup	Hybrid backup	Indirect 2-Tank TES	None

* All cases assume Kramer Junction 1999 radiation 8.054 kW/m^2/day.

** Solar Only / Hybrid Operation

Cost reductions in parabolic trough plants are discussed from a reference point of the nine operating SEGS plants in the California Mojave Desert. Future cost reductions derive from technical improvements, scale-up in individual plant megawatt capacity, increased deployment rates, competitive pressures, use of thermal storage, and advancements in O&M methods. Cost drivers have been identified from SunLab activities and from industry input. Duke Solar Energy is a key industrial participant in trough technology and is actively engaged in developing trough power plant opportunities as well as an advanced collector design.

The development and operation of the SEGS plants by Luz International, totaling 354 MWe net installed capacity, provide the baseline for future performance and cost projections. Projected cost reductions are tied to the future development path shown in Table 4-2.

Table 4-2 — Trough Technology Summary for SunLab Technology Cases

		SunLab Technology Cases		
Case	**Baseline**	**Near Term**	**Mid Term**	**Long Term**
Project	**SEGS VI Hybrid**	**Trough 100**	**Trough 100**	**Trough 400**
In Service	**1989**	**2004**	**2010**	**2020**
Net Power (MWe)	30	100	150	400
Capacity Factor (%)	22 (solar only)	54%	56%	57%
Solar Field (km^2)	0.188	1.120	1.477	3.910
Heat Transfer Fluid	VP-1	VP-1	Hitec XL	Advanced
Solar Field Operating Temperature (^oC)	391	391	500	500
Thermal Storage (hrs)	0	12	12	12
Thermal Energy Storage	NA	Indirect 2-Tank	Direct Thermocline	Direct Thermocline
Thermal Storage Fluid	NA	Solar Salt	Hitec XL	Advanced
Land Area (km^2)	0.635	3.780	4.98	13.189

However, the actual strategy employed by the plant suppliers can be significantly diverse, with more emphasis on near-term cost reduction with a minimum of risk. As discussed above, for the near-term, the suppliers may opt to provide multiple plants in the 50-MWe to 100-MWe size range with no thermal storage but with a supplemental steam generator, replicating the proven technology of the existing SEGS plants. In a series of evolutionary design improvements, the following major advancements formed the basis of the SunLab estimates:

- Collector
  - A comprehensive series of wind tunnel tests on parabolic trough collector models was carried out in 2001–2002, establishing design pressure force coefficients for various wind approach angles and collector orientations, with and without a wind fence.
  - Using these coefficients, finite element methods stress analyses were used to optimize the collector structure for wind survival conditions, minimizing collector weight and defining design parameters for mirror strength, pylons, and foundations. With more tightly known design parameters, the collector weight, and thus costs, can be lowered.

- High efficiency and durable receivers are assumed to be developed, with selective surfaces (consisting of special selective coatings on the metal tube receivers) to maximize the absorption of incident solar radiation and minimize radiation losses from the receiver. High efficiencies result in smaller solar fields for a given thermal energy delivery and in longer lifetimes to reduce operation and maintenance costs.
- Advanced receivers are assumed utilizing selective surfaces that can operate efficiently at temperatures of 500°C or higher, paving the way for major advancements in thermal storage and power block operation for trough plants.
- Alternative mirror design development using thin-glass with non-metallic structural elements or using thin silverized films is assumed. Both approaches reduce weight and offer less expensive reflector options.

- Heat transfer fluid (HTF)
  - Alternate HTFs, such as inorganic molten salts and ionic fluids, are being investigated that will permit operation at higher temperatures (at or above 500°C), leading to lower thermal storage costs and higher power block efficiencies.
- Thermal Storage System
  - The Solar Two two-tank molten salt storage system is designed for commercial operation in a trough plant for the case of the conventional synthetic oil HTF. Termed an indirect storage system, this also requires an oil-to-salt heat exchanger in the system.
  - This same two-tank molten salt storage system is designed for direct operation with a molten salt HTF.
  - A single-tank direct molten salt thermocline system is designed to reduce thermal storage costs.
- Electric Power Block
  - The efficiency of a SEGS-type plant is improved by refining the integration of the solar field with the power block.
  - Turbine efficiencies are improved through use of the higher temperature heat transfer fluids in the solar field.

4.2 EFFICIENCY

The efficiency of the existing SEGS parabolic trough plants has been well documented and provides the basis for evaluating the potential performance improvements of future parabolic trough plants. SEGS VI, a 14-year-old 30-MWe plant currently in operation in California, is used as a reference plant to evaluate future efficiency improvements. SEGS VI was selected because it was the last plant built using all second-generation Luz collector (LS-2) technology. The later third-generation Luz collector (LS-3) used at the larger 80-MWe SEGS plants had alignment problems and never operated at the same level of performance achieved at SEGS VI.

The technological advances and research, upon which the SunLab efficiency improvement estimates are based, include the following:

- The development of the new Solel UVAC receiver. The UVAC has improved thermal and optic properties. Field tests of the new receiver at SEGS VI shows a 20% increase in thermal performance compared to original receiver tubes.
- The development of ball joint assembly replacements for flexhoses. A demonstration of new ball joint assemblies has been shown to reduce the hydraulic pressure drop in the solar field by approximately 50%. This results in lower solar field heat transfer fluid pumping electric parasitics.
- Improvements in mirror washing techniques have resulted in increased solar field average mirror reflectance.
- Investigation of higher temperature heat transfer fluids.
- Research of direct thermal energy storage.
- Research of higher temperature receiver selective coatings.

Table 4-3 shows a breakdown of the elements that contribute to the annual efficiency. The table shows both the SunLab goal efficiencies and the S&L estimates based on a less aggressive technology development scenario. A more detailed breakdown of all the SunLab cases is shown in Appendix D. The SEGS VI data are based on actual plant data from 1999.

Table 4-3 — Trough Annual Efficiency Summary

		SunLab Forecast			Sargent & Lundy		
Case	**Base-line**	**Near Term**	**Mid Term**	**Long Term**	**Near Term**	**Mid Term**	**Long Term**
Project	**SEGS VI**	**Trough 100**	**Trough 150**	**Trough 400**	**Trough 100**	**Trough 150**	**Trough 400**
Year In Service	**1989**	**2004**	**2010**	**2020**	**2004**	**2010**	**2020**
Solar Field Optical Efficiency	0.533	0.567	0.598	0.602	0.567	0.570	0.570
Receiver Thermal Losses	0.729	0.860	0.852	0.853	0.843	0.810	0.810
Piping Thermal Losses	0.961	0.965	0.967	0.968	0.965	0.967	0.968
Storage Thermal Losses	NA	0.991	0.996	0.996	0.991	0.996	0.996
EPGS Efficiency	0.350	0.370	0.400	0.400	0.370	0.400	0.400
Electric Parasitic Load	0.827	0.884	0.922	0.928	0.884	0.922	0.928

Case	Base-line	SunLab Forecast Near Term	SunLab Forecast Mid Term	SunLab Forecast Long Term	Sargent & Lundy Near Term	Sargent & Lundy Mid Term	Sargent & Lundy Long Term
Project	**SEGS VI**	**Trough 100**	**Trough 150**	**Trough 400**	**Trough 100**	**Trough 150**	**Trough 400**
Year In Service	**1989**	**2004**	**2010**	**2020**	**2004**	**2010**	**2020**
Power Plant Availability	0.980	0.94	0.94	0.94	0.94	0.94	0.94
Annual Solar-to-Electric Efficiency	**10.6%**	**14.3%**	**17.0%**	**17.2%**	**14.0%**	**15.4%**	**15.5%**

4.2.1 Solar Field Optical Efficiency

The solar field optical efficiency includes incident angle effects, solar field availability, collector tracking error and twist, the geometric accuracy of the mirrors to focus light on the receiver, mirror reflectivity, cleanliness of the mirrors, shadowing of the receiver, transmittance of the receiver glass envelope, cleanliness of the glass envelope, absorption of solar energy by the receiver, end losses, and row-to-row shadowing. The SunLab projected improvements in optical efficiency are due primarily to improvements in the receiver optical properties, including the following:

- **Receiver Solar Absorptance.** Significant improvements in selective coatings have occurred since the last SEGS plant was built. The solar absorptance of the cermet tubes used at SEGS VI was approximately 91.5%. According to test data, the Solel UVAC receiver tubes have a solar weighted absorptance of 94.4% and further optimization of the selective coating is expected to yield solar absorptances of 96% or higher.
- **Receiver Glass Envelope Transmittance.** Anti reflective coatings for glass have been improved in the last 10 years to improve durability. The new receiver tubes have anti-reflective coatings that deliver solar transmittances of 96.5% compared with earlier coating that only allowed 92.5%.
- **New Front Surface Reflectors.** New front surface reflectors with solar-weighted reflectivity of 95% are assumed for the SunLab long-term case compared to 93.5% for current thick glass mirrors.

The S&L evaluation is based on a less aggressive technology development approach, basing the maximum optical efficiency on the tested receiver tubes weighted absorptance of 94.4% and receiver coatings solar transmittances of 96.5%.

4.2.2 Receiver Thermal Losses

Receiver thermal losses are primarily driven by the thermal emittance of the receiver's selective coating (radiation losses) and by the vacuum in the receiver (convection losses). As long as vacuum is maintained, convection losses are negligible. Radiation losses, on the other hand, are a function of the receiver's absolute surface temperature to the fourth power. The thermal emittance measures the ability of the surface to radiate energy away from the receiver. The lower the thermal emittance, the lower the radiation losses from the surface.

- **Receiver Thermal Emittance.** SEGS VI had a combination of black chrome and the original generation of Luz Cermet receiver tubes. The average thermal emittance of these tubes is approximately greater than 20% at 350°C. The UVAC receiver first installed at SEGS VI had a thermal emittance of 14% at 400°C. According to tests performed for Solel, the second-generation UVAC receiver had a thermal emittance of about 9% at 400°C. SunLab currently has a research and development effort exploring high temperature coating designs with low thermal emittance and high solar absorptance.

- **Receiver Reliability.** As long as vacuum is maintained, convective thermal losses are minimal from the receiver. When receivers lose vacuum, the thermal losses from the receiver are approximately doubled. Breakage of the glass envelope results in significantly higher thermal losses. Loss of vacuum and breakage of the receiver glass envelope have been significant issues at the existing SEGS plants.

4.2.3 Piping Thermal Losses

Piping thermal losses corresponds to thermal losses from the solar field header piping and heat transfer fluid (HTF) system piping. Piping heat losses are a function of the piping surface area and the temperature of the fluid in the pipe above ambient temperature. Nexant has developed a parabolic trough solar field piping model for sizing the layout of piping headers. This model has been used to determine the heat losses for the various cases. The piping model has been baselined against the thermal performance of the SEGS VI solar field.

- The near-term case operates at temperatures similar to SEGS VI (391°C), thus the heat losses are considered to be similar.

- Piping losses in future cases are similar due to a combination of offsetting factors. The mid-term case is based on operating at a higher temperature of 450°C and maintaining the field at a minimum of 150°C during non-operational periods to prevent the molten-salt HTF from freezing. This higher temperature results in increased thermal losses per unit area of piping. However, the new salt fluid has a higher density that requires lower flow rates and smaller heater piping. These result in the thermal losses from the solar field being reduced. The long-term case is based on operating at higher temperatures (500°C) and lower flow rates.

4.2.4 Storage Thermal Efficiency

Thermal storage efficiency accounts for thermal losses from the thermal storage system. Storage thermal losses are a function of the surface area of the storage tanks and the temperature of the fluid above ambient. Large high temperature thermal storage systems have been demonstrated at the SEGS I trough plant and Solar Two power tower. In these systems, thermal losses have been shown to be minimal; thus the storage thermal efficiency approaches 100%. Nexant has developed a thermal storage design model, which was used to determine the heat losses. This model is based on the Solar Two thermal storage design and operational experience.

- Storage thermal losses for the near-term trough plants are slightly larger for trough plants than for tower plants. Due to the smaller temperature difference between the hot and cold storage tanks in the trough plant, the thermal storage system must be larger to hold the same amount of thermal energy. Thus, there is more surface area for the trough plant. However, the hot tank temperature at the trough plant will be lower than the tower plants and the thermal losses per unit area of tank will be lower. Overall, storage losses are slightly larger at the trough plant; however, the storage thermal efficiency is still greater than 99%.
- Mid-term and long-term thermal storage systems operate at higher temperatures; however, the temperature difference between hot and cold is greater. As a result, a smaller volume is required to store energy. Also, single tank thermocline storage systems are anticipated. These further reduce the required tank volume by replacing a large fraction of the storage fluid with low cost filler, sand and gravel, that typically has a higher volumetric heat capacity than the fluid it is replacing. Therefore, even though future thermal storage systems operate at higher fluid temperatures, the surface area of the thermal storage system is reduced compared to the near-term storage case and results in improved storage thermal efficiency.

4.2.5 Turbine Cycle Annual Efficiency

The turbine cycle annual efficiency accounts for the design point turbine cycle efficiency, start-up losses, part-load operation, and losses due to minimum turbine load requirements (especially important for plants without thermal storage).

- The near-term case has the same turbine cycle design point efficiency as SEGS VI (37.7%); however, because of thermal storage, the annual turbine cycle efficiency is better than the case without thermal storage. The near-term plant with thermal storage has a higher capacity factor than SEGS VI (47% versus 34%). Thus, the number of turbine start-ups per MWh generated is lower. Thermal storage allows the plant to operate more hours at full load close to peak efficiency and reduces the number of hours the plant is operating at part load efficiencies. Thermal storage also allows thermal energy to be collected even when it is not sufficient to operate the power plant.
- The power cycle efficiency of the mid-term and long-term cases increases to 39% and 40% as solar field operating temperatures are increased to 450°C and 500°C, respectively.

4.2.6 Electric Parasitic Load

The main parasitic electric loads are the motors for the heat transfer fluid (HTF) pumps, condensate/feedwater pumps, cooling water pumps, cooling tower fans, and boiler of heater forced draft fans. Additional parasitic loads are a result of instrumentation, controls, computers, valve actuators, air compressors, and lighting. The solar field also adds parasitic loads for the collector drives and communications.

- A significant reduction in parasitic electric load for the near-term trough technology is based primarily on the replacement of flex hoses with balljoint assemblies in the solar field. These ball-joint assemblies reduce the pressure drop across the solar field by approximately 50%. The addition of thermal storage is also expected to reduce parasitics by spreading the station load over increased annual generation.
- A further reduction in pumping parasitics will occur when the switch is made to molten-salt HTF. Because of the higher density of molten salt, lower volumetric HTF flow rates, and thus less pumping power, are required.

4.2.7 Power Plant Availability

Availability accounts for forced and scheduled outages and deratings of the power plant. Typically, plant availability is only affected if solar energy collection/conversion is reduced by an outage or derating.

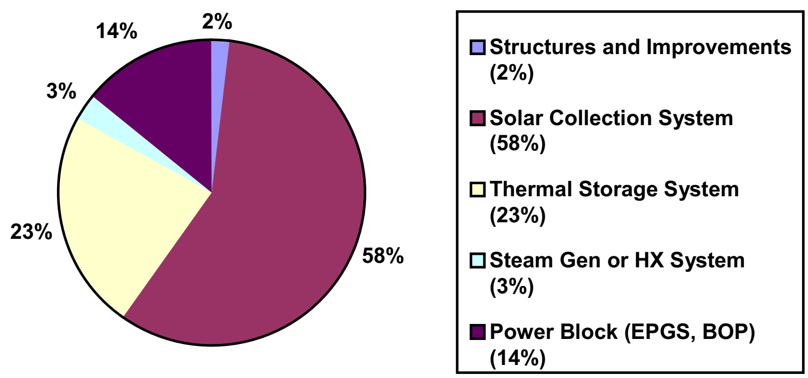
- For the most part, the SEGS plants have demonstrated very high power plant availability. Normally, plants will take a 1- to 2-week outage during the winter to conduct required annual inspections and any corrective maintenance that cannot be accomplished during the normal daily operation. Every 10 years, a 5-week major turbine overhaul is conducted. During 1999, SEGS VI had a power plant availability of approximately 98% but did not take any planned scheduled maintenance outages during the year.
- Future plants are conservatively assumed to have a 6% annual outage rate. This includes both scheduled and forced outages.

If a higher temperature HTF and compatible thermal storage system can be developed and implemented in the mid-term, a 17.0% annual net solar-to-electric efficiency is feasible. Additional investigation and development of storage systems, including the optimum HTF for steam cycle efficiency and storage compatibility is required to achieve the mid-term efficiency projection. Long-term objectives will require continuing investigation and development of thermal storage systems and high temperature HTF. The long-term objectives will also necessitate an advanced HCE absorber coating for the projected 500°C operating temperature.

4.3 EVALUATION OF MAJOR COST COMPONENTS

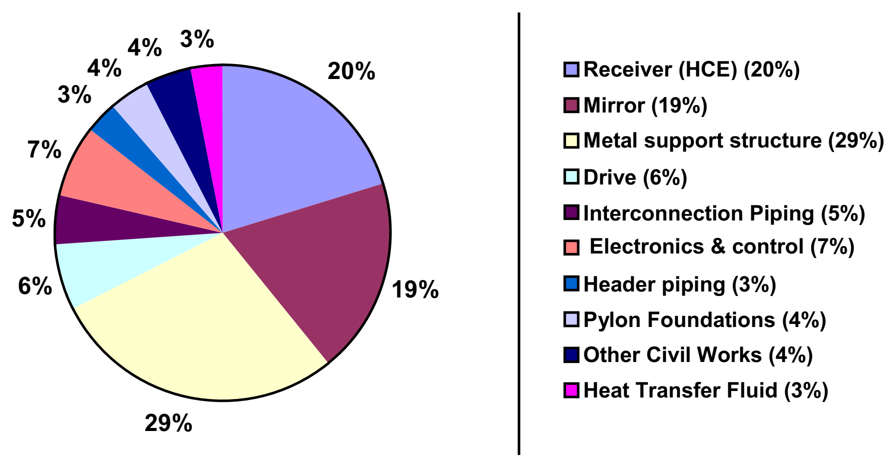
The major cost contributors in direct cost of a parabolic trough solar plant with thermal storage are the solar collector field (53%), thermal storage system (23%), and power block (14%), as illustrated in Figure 4-1.

Figure 4-1 — Major Cost Categories for Parabolic Trough Plant
2004 Near-Term Case: 100 MWe, 12 hours TES, 2.5 Solar Multiple



The major component costs in the solar field are illustrated in Figure 4-2. The key cost elements in the solar field are the receiver (20%), the mirrors (19%), and the concentrator structure (29%).

Figure 4-2 — Solar Field Component Cost Breakdown for Parabolic Trough Plant
2004 Near-Term Case: 100 MWe, 12 hours TES, 2.5 Solar Multiple



The S&L review focuses on these five major cost components: concentrator structure, mirrors, receivers, thermal energy storage, and the power block. Table 4-4 provides a summary of the SunLab and S&L cost projections for these five cost elements.

Table 4-4 — Trough Capital Cost Summary

Case	Base-line	SunLab Near Term	SunLab Mid Term	SunLab Long Term	Sargent & Lundy Near Term	Sargent & Lundy Mid Term	Sargent & Lundy Long Term
Project	**SEGS VI**	**Trough 50**	**Trough 150**	**Trough 400**	**Trough 50**	**Trough 150**	**Trough 400**
In Service	**1989**	**2004**	**2010**	**2020**	**2004**	**2010**	**2020**
Solar Collection System ($/m^2)	250	234	161	122	234	195	181
Support Structure, $/m^2	67	61	54	46	67	56	52
Heat Collection Elements, $/unit	847	847	635	400	847	675	525
Mirrors, $/m^2	43	43	28	18	40	32	26
Power Block, $/kWe	527	367	293	197	306	270	198
Thermal Storage, $/kWe	NA	958	383	383	958	383	383
Total Plant Cost, $/kWe	3,008	4,856	3,416	2,225	4,816	3,562	3,220

4.3.1 Solar Field Support Structure

The structure consists of the metal support system of the collectors consisting of the pylons and reflector support elements. Wind loads during maximum wind speeds dictate the required strength of these units. Recent wind tunnel testing has provided improved data for use in optimizing the structural design, and reducing the weight, necessary for long-term reliability.

The SunLab projections for the structure material and erection are shown in the following Table 4-5.

Table 4-5 — SunLab Cost Projections

		Reduction from SEGS VI	$/kWe
SEGS VI	$67/m^2	—	420*
2004	$61/m^2	9%	683
2007	$57/m^2	15%	591
2010	$54/m^2	19%	531

		Reduction from	
		SEGS VI	$/kWe
2015	$50/m^2	25%	489
2020	$46/m^2	31%	450

*Smaller solar field per kWe due to no storage.

The baseline cost of $67/m^2 is consistent with estimates prepared by Pilkington International (1999) indicating $63/m^2. Cost comparisons based on weight for the various structures are illustrated below in Table 4-6. Additional cost reductions will be realized by minimization of the number of required parts, simplification of fabrication and field erection reducing labor costs for on-site assembly and erection. This cost reduction potential has not been quantified in this evaluation since there has not been an actual erection of a new collector structure. The individual metal parts of the structure can readily be manufactured by suppliers worldwide, leading to potential cost reductions through competition. However, structure cost reductions due to commercialization were not specifically considered in this evaluation.

Table 4-6 — Costs of Various Structures

LS-2	$58/m^2
LS-3	$66/m^2
EuroTrough	$58/m^2
Duke Solar	$48/m^2
IST	$48/m^2

Based on the current activity in progress by the various suppliers, obtaining the projected cost reductions for the structure represents a low risk. The current weight reduction presented by the suppliers has the potential to meet the projected cost reduction.

4.3.2 Solar Field Heat Collection Elements (HCE)

The receivers, or heat collection elements (HCEs), are a major contributor to trough solar field performance. Luz manufactured this solar field component in-house, which has continued under Solel Solar Systems who acquired the Luz manufacturing facilities. HCEs supplied to the SEGS plants for spare parts over the last decade by Solel have shown improvements in performance and reliability. These include improved optical properties with regards to absorptivity and better protection of the glass-to-metal seal to increase in-service lifetime. The SunLab projected HCE deployment and costs are shown in Table 4-7.

Table 4-7 — SunLab Projected HCE Deployment and Costs

Project	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
In Service	1999	2004	2007	2010	2015	2020
Number of HCE	9,600	57,216	45,700	65,072	86,101	172,201
Number of HCE Accumulative	9,600	66,816	112,516	177,588	263,688	435,889
Cost, $/m^2 field	43	43	34	28	22	18
Cost, $/unit	847	847	762	635	508	400

A comparison of the S&L estimated HCE costs and the SunLab projected costs is shown below in Table 4-8.

Table 4-8 — Comparison of HCE Costs

Year	SunLab Projected Cost, $/unit	S&L Estimate, $/unit
2004	847	847
2007	762	762
2010	635	675
2015	508	625
2020	400	600

The heat collection elements, which constitute a major portion of the direct capital cost, currently have only one supplier (Solel). Additional suppliers will promote competition and reduce costs. A major European and worldwide specialty glass parts supplier, Schott Rohrglas, has recently announced its intent to produce this component. An increase in the number of HCEs as projected by SunLab will reduce the cost based on the experience curve cost reduction, but not to the projected $400/unit.

Advanced development of the HCE is required for the higher operating temperatures in the planned molten-salt heat transfer fluid (HTF) applications, as discussed in the thermal storage section of this report. Additional development is also required to address the excess failure rates that have occurred at the SEGS plants compared to expected levels. The HCE development focus now is on developing a more robust and lower cost glass-to-metal seal design and on identifying higher-temperature selective coating with better thermo/optic properties. Sandia has identified new materials that could be used in the glass-to-metal seal to reduce the potential stress in the seal. In general, however, the current Housekeeper seal used in the HCE is very expensive and a significant part of the total receiver cost. Sandia has also identified some new glass-to-metal seal options that have the potential to be much lower in cost to manufacture and be more robust at the same time. NREL has been evaluating new selective coatings. Several new cermet coatings have been identified that may be easier to manufacture and have better thermo/optic properties. These are multi-layer cermets as opposed to the graded cermet used by Solel. The graded cermets require a sputtered manufacturing process, whereas the multilayer coating can probably be deposited with simpler coating processes and should also have better quality control of the final properties. NREL is also looking into changing the materials used in the cermet to give better high temperature performance and stability. Both the design work and the coating development are being funded in the current DOE budget and will be continued next year.

Alternate HCE designs (Zhang et al. 1998; Morales and Ajona 1998; San Vicente, Morales, and Gutiérrez 2001), which are in various stages of development, indicate a lower cost than the Solel UVAC HCE, but at reduced efficiency levels. Reduced HCE efficiency will result in a lower net annual solar-to-electric efficiency and require a larger collector area. As noted above, Schott Rohrglas, a large international supplier of specialty glass and related products, has recently announced its entry into the HCE supply market. However, start-up of HCE production is a significant cost, and a viable market growth is imperative to justify market entry for a new supplier.

4.3.3 Solar Field Mirrors

The reflectors used in the SEGS plants consist of 4-mm low-iron float glass mirrors thermally sagged during manufacturing into a parabolic shape. A single manufacturer supplied the mirrors for the SEGS plants at construction and for spare parts since that time. Mass production and competition can lower the cost significantly, as can technical improvements. The SunLab projected mirror costs are shown in Table 4-9.

Table 4-9 — SunLab Projected Mirrors Costs

Project	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
In Service	1999	2004	2007	2010	2015	2020
Mirrors, $/m^2 field	40	40	36	28	22	16

Alternatives to glass mirror reflectors have been in service and under development for more than 15 years. It is noted that all the identified alternatives are in various stages of initial development or testing. The major current developments are listed below.

- Thin glass mirrors are as durable as a glass reflector and relatively lightweight in comparison to thick glass. However, the mirrors are more fragile, which increases handling costs and breakage losses. To address corrosion problems, new thin glass experimental samples were recently developed and are being tested under controlled conditions.
- 3M is developing a nonmetallic, thin-film reflector that uses a multi-layer *Radiant Film* technology. The technology employs alternating co-extruded polymer layers of differing refractive indices to create a reflector without the need for a metal reflective layer. 3M plans to develop an improved solar reflector with improved UV screening layers and a top layer hardcoat to improve outdoor durability.
- ReflecTech and NREL are jointly developing a laminate reflector material that uses a commercial silvered-polymer reflector base material with a UV-screening film laminated to it to result in outdoor durability. Initial prototype accelerated-exposure test results have been promising, although additional work on material production is needed. The material would also benefit from a hardcoat for improved washability.
- Luz Industries Israel created a front surface mirror that consists of a polymeric substrate with a metal or dielectric adhesion layer; a silver reflective layer; and a proprietary, dense, protective top hardcoat.
- SAIC of McLean, Virginia, and NREL have been developing a material called *Super Thin Glas*s. This is also a front surface mirror concept with a hard coat protective layer.
- Alanod of Germany has developed a front surface aluminized reflector that uses a polished aluminum substrate, an enhanced aluminum reflective layer, and a protective oxidized alumina topcoat. These reflectors have inadequate durability in industrial environments. A product with a polymeric overcoat to protect the alumina layer has improved durability.

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

Based on the current activity underway by the various suppliers, obtaining the projected cost reductions for the mirrors represents a low risk. The current costs presented by the suppliers have the potential to meet the projected cost reduction. Having active suppliers performing development promotes lower costs through competition. It is expected a portion of the mirror development will be in the realm of the manufacturers.

4.3.4 Power Block

There are recognized scale-up cost reductions for the power block. Using the SOAPP software program (SOAPP undated), S&L estimated the scale-up factor for increasing the plant size from 100 MW to 400 MW, as depicted on Figure 4-3. The projected SunLab values are included for comparative purposes. Power block costs (Figure 4-3A) include the steam turbine and generator, steam turbine and generator auxiliaries, feedwater, and condensate systems. Balance-of-plant costs (Figure 4-3B) include general balance-of-plant equipment, condenser and cooling tower system, water treatment system, fire protection, piping, compressed air systems, closed cooling water system, plant control system, electrical equipment, and cranes and hoists.

Figure 4-3A — Scale-Up Cost Reductions: Power Block ($/kW)

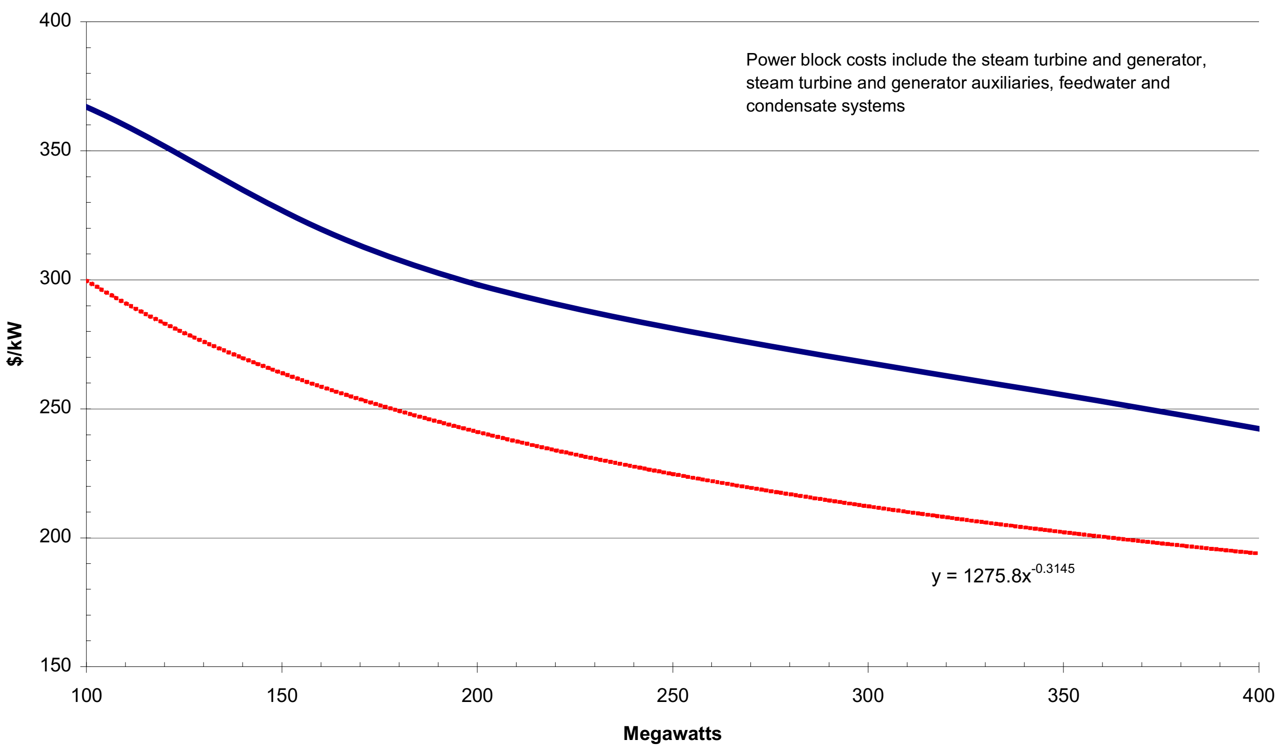
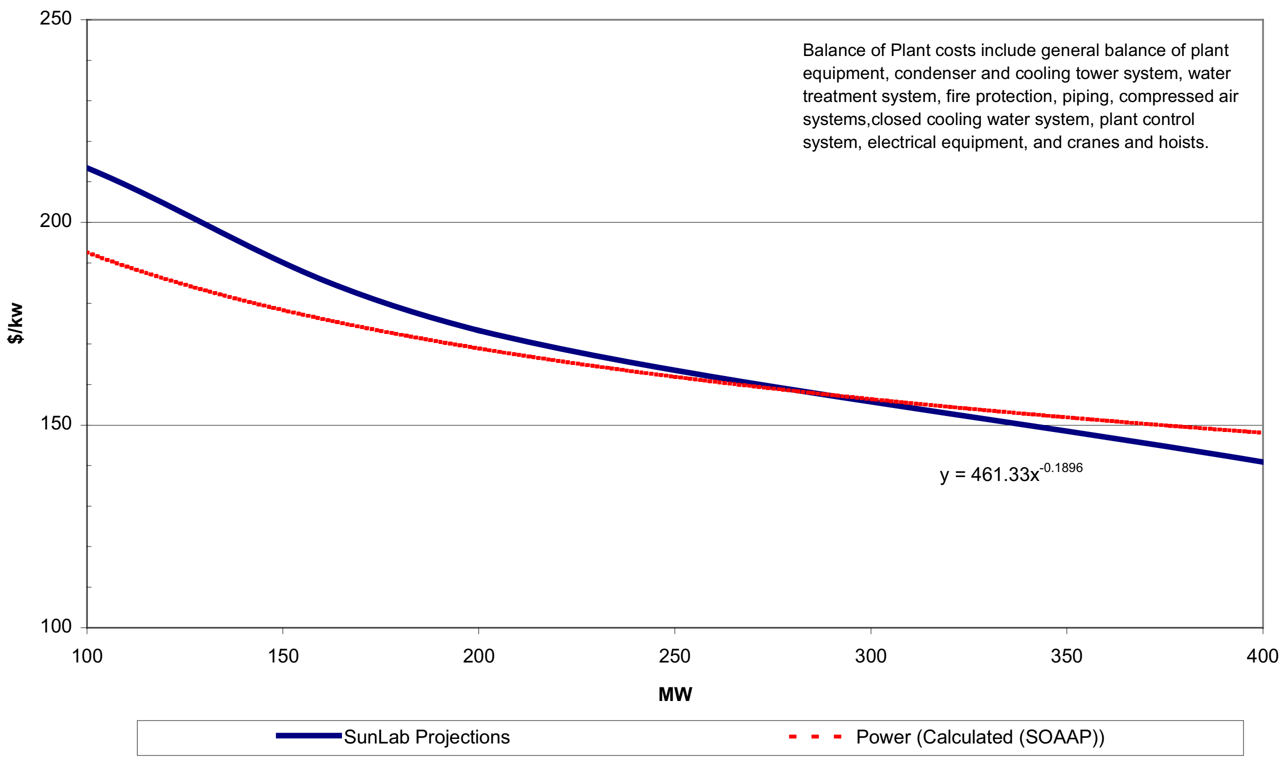


Figure 4-3B — Scale-Up Cost Reductions: Balance-of-Plant ($/kW)



A comparison of the SunLab projected cost versus the SOAPP predicted $/kW cost for the power block plus the balance-of-plant is shown in Table 4-10.

Table 4-10 — Power Block and BOP Cost Comparison

Total Power Block + BOP	2004 – 2007	2010	2015	2020
Plant size, MWe	100	150	200	400
SunLab Projected Cost, $/kWe	581	525	472	383
SOAPP Estimate Cost, $/kWe	499	450	399	346

The estimated costs based on the SOAPP program indicate that the SunLab projected costs for the power block are conservative (on the high side), approximately $50/kW higher than estimated by the SOAPP program. The SunLab power block cost estimates are based on a 1990 ABB quotation for a 100-MW steam turbine. The ABB quotation was escalated and scaled-up for the larger sizes. The SunLab power block cost estimates are based on dated information, and the escalation and scale-up factors add to the uncertainty of the data with respect to current pricing. Equipment prices in the SOAPP program reflect 2001 actual costs. Since the SOAPP pricing is current, the SOAPP-generated costs were used in this evaluation.

As previously discussed, to achieve the near-term increased Rankine cycle efficiency, the HTF will have to be changed to obtain higher inlet steam temperatures. For the near-term, additional development and field testing is required on alternate HTF for higher temperature applications. For the long-term, not only is alternate HTF development required but the current HCE absorber coating upper temperature limit must be raised by new developments to the projected 500°C operating temperature.

4.3.5 Thermal Storage

The SunLab projected thermal storage costs are shown in Table 4-11. Note that the SunLab projections are based on 12 hours of thermal storage for each case.

Table 4-11 — SunLab Projected Thermal Storage Cost

		2004	2007	2010	2015	2020
Plant size, gross, MWe		110	110	165	220	440
Storage, MWh_t		3,525	3,349	4,894	6,525	13,050
Type		Indirect Two-Tank	Direct Thermocline	Direct Thermocline	Direct Thermocline	Direct Thermocline
Heat Transfer Fluid		VP-1 / Solar Salt	HitecXL	HitecXL	HitecXL	HitecXL
HTF Temperature, °C		400	450	500	500	500
SunLab Projected	$/$kWh_t$	27.1	12.7	11.7	11.7	11.7
	$/kWe	958	425	383	383	383

Definitive cost estimates for an indirect two-tank storage system based on detailed design drawings and material takeoffs were developed by Nextant. The unit costs were $36.4/$kWh_t$ for a 470-kWh_t system and $31/$kWh_t$ for a 688 kWh_t system. The SunLab projection appears to be conservative (on the high side) based on the previous estimates.

However, the goal to reduce the thermal storage system capital cost in the $10/$kWh_t$ to $12/$kWh_t$ range will require additional investigation and development of both indirect and direct storage systems, including the optimum HTF and storage fluid for steam cycle efficiency and storage compatibility. The amount and type of storage have significant impacts on the total cost of the plant and are key considerations for cost reductions.

The year 2007 projection for a direct thermocline storage uses HitecXL (ternary) HTF in both the solar field and the thermal storage system, which eliminated the need for the heat exchangers between the solar field and storage system. In addition, the solar field can be operated to higher outlet temperatures (450°C), increasing the power cycle efficiency and further reducing the cost of thermal storage. The 2007 direct thermocline storage value of $12.7/kWh$_t$ in the SunLab projection appears to be reasonable, if the direct thermocline storage system is successfully developed, based on the following:

- The power tower storage cost is $8.3/kWh$_t$ for 12 hours at Solar 100.
- Trough plants have a smaller temperature differential in the thermal energy storage system 450°C – 293°C (157°C) vs. 566°C – 288°C (278°C) in tower plants.
- Trough plants have a lower power cycle efficiency, 39% at 450°C vs. 44% at 550°C.
- The trough plants use a thermocline storage system that eliminates one tank and replaces the majority of storage fluid with a lower-cost filler material. Nextant estimates indicate that a 35% cost reduction can be achieved going from a two-tank system to a thermocline system.

Trough Storage Cost (2007) = $8.3/kWh$_t$ * (278°C/157°C) * (44%/39%) * (1-0.35)
= $10.7/kWh$_t$

Subsequent projections after the year 2007 also use a direct thermocline system with HitecXL (ternary) solar salt as the storage media and HTF. The SunLab TES cost estimate of $11.7/kWh$_t$ appears to be reasonable, if the solar field can be operated to higher outlet temperatures of 500°C and an advanced heat collection element for the 500°C HTF operating temperature is developed, based on the following calculation:

Trough Storage Cost (2010) = $8.3/kWh$_t$ * (278°C/207°C) * (44%/40%) * (1-0.35)
= $7.9/kWh$_t$

4.3.6 Total Investment Costs

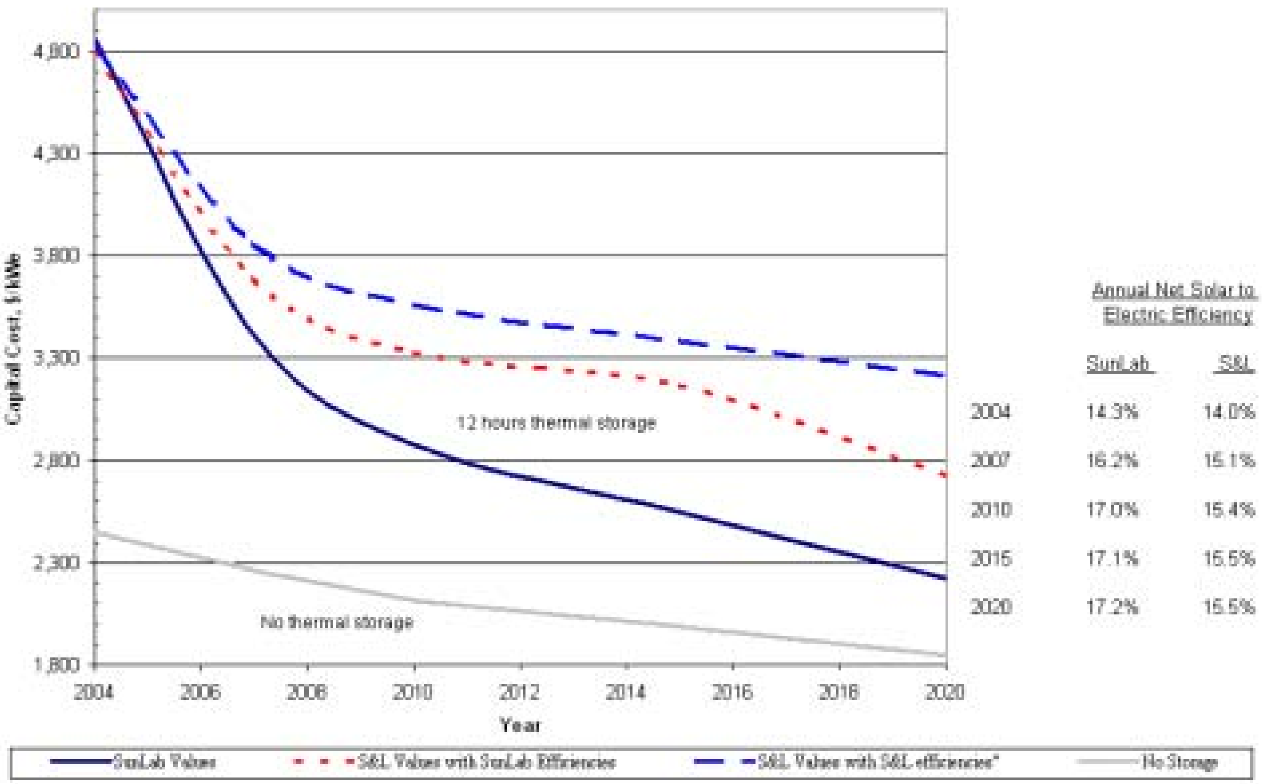
The SunLab model projects parabolic trough plant capital and O&M costs based on various technology advances and commercial deployment predictions. The SunLab projections are considered the best-case analysis where the technology is optimized and a high deployment rate is achieved. S&L developed capital and O&M costs based on a more conservative approach whereby the technology improvements are limited to current demonstrated or tested improvements and with a lower rate of deployment than used in the SunLab model. The two sets of estimates, by SunLab and S&L, provide a band in which the costs can be expected to fall. The capital costs without thermal storage is included for informational purposes.

Table 4-12 and Figure 4-4 illustrates the SunLab projected total installed capital cost ($/kWe) compared to S&L's more conservative values. Figure 4-4 also shows the total installed capital cost based on achieving the annual net efficiencies projected by SunLab, but not the projected cost reductions. The curves highlight the impact of the annual net efficiencies on the capital cost. The curves also indicate that additional cost reductions above and beyond the more conservative S&L values, due to technology improvements and increased deployment rates, will result in convergence of the capital costs toward the SunLab values.

Table 4-12 — Comparison of Total Investment Cost Estimates ($/kWe): SunLab vs. Sargent & Lundy

	2004	2007	2010	2015	2020
SunLab	$ 4,859	$ 3,408	$ 2,876	$ 2,546	$ 2,221
S&L – S&L Efficiencies	4,816	3,854	3,562	3,389	3,220
S&L – SunLab Efficiencies	4,791	3,687	3,331	3,165	2,725
S&L – No Storage	2,453	2,265	2,115	1,990	1,846

Figure 4-4 — Total Installed Capital Costs: Operations and Maintenance



Sargent & Lundy reviewed the SunLab O&M cost model based on our experience with fossil and other power plant technologies and in the course of a site visit to KJC Operating Company, the operator of the five 30-MWe trough projects located at Kramer Junction. KJC Operating Company provided proprietary information on the last five years of operation. The SunLab O&M estimate is based largely on the experience at the KJC Operating Company SEGS plants. The model assumes a stand-alone trough power plant (as opposed to the five co-located plants at Kramer Junction) and adjusts cost depending on the size of the solar field and total electric generation per year. It breaks out the specific staffing requirements for operations and maintenance crews for both the conventional power plant and for the solar field. Administrative staffing is also included. In addition to labor breakdown, the model breaks out service contracts, water treatment costs, spares and equipment costs, miscellaneous costs, and periodic capital equipment requirements. S&L conducted a review of the SunLab model and compared it to general power industry experience.

The Sargent & Lundy O&M costs for comparison to the SunLab projections are based on the following:

- Solar Field
  - The initial unit costs are based on the SunLab values, and cost reductions for years beyond 2004 are based on a PR = 0.92
  - Replacement rate for the mirrors and HCE are based on the average actual replacement rates for SEGS III – VII for the period 1997–2001
  - The replacement rates for the balance of the solar field are based on the SunLab values
- Power Block and Balance-of-Plant
  - Costs are based on S&L data for the respective MW-size plant for the steam turbine systems and balance-of-plant
- Water and Process
  - Costs are based on the average actual costs for SEGS III – VII for the period 1997–2001
- Staffing, Services Contracts, Miscellaneous, and Capital Equipment
  - The costs are based on the SunLab values since the SunLab values were determined to be reasonable
- Thermal Storage
  - The costs are based on 0.4% of the capital cost per annum

Analyzing the two estimates revealed the major component to account for the cost difference is the HCE replacement rate. Table 4-13 shows a comparison of the SunLab and S&L projected replacement rates.

Table 4-13 — Projected Trough Receiver Replacement Rates

Annual Failures (Percent of Field)	Current	2004	2007	2010	2015	2020
SunLab	3.5%	2%	1%	0.5%	0.5%	0.5%
S&L	5.5%	5.5%	2.5%	1.5%	1.0%	0.5%

The SunLab near-term values are not consistent with the average actual HCE replacement rate of 5.5% reported for SEGS III – VII for the period 1997–2001.

Sargent & Lundy reviewed the actual receiver (HCE) replacement rate reported by KJC Operating Company over the last five years. The S&L evaluation is based on total HCE replacement reported for the SEGS III – VII for the period 1997–2001. S&L's evaluation is based on the current replacement rate at all the SEGS plants, with step reductions in the replacement rate based on the following considerations:

- The average actual HCE replacement rate of 5.5% was reported for SEGS III – VII for the period 1997–2001. The total HCE replacement includes breakage and fluorescence. Fluorescence is due to cermet coating failures. This failure is due to the existence of molybdenum in the original Luz cermet coating. Solel no longer uses molybdenum in the UVAC cermet coating, so this type of failure will presumably no longer occur. Eliminating replacements due to these failures reduces the site failure/replacement rate.
- SunLab used the SEGS VI plant as the baseline reference plant. The SEGS III – V plants had problems during initial startup and the early years of operation that caused bowing of the HCEs, which increased breakage at those plants. SEGS VII has had higher breakage on the LS-3 half of the field, although the LS-2 failures are similar to SEGS VI. SEGS VI was the last full plant constructed with LS-2 collectors and represents the most mature version of this generation of collector technology. The HCE total replacement rate at SEGS VI during the 5 years is in the 5.5% range. Discounting the fluorescence failures, the replacement rate was 4.2% over the 5-year period.
- The high HCE failure rate at the existing plants is due in part to issues that would not be found at a future plant. A significant portion of the failures has been due to the hydrogen remover (HR) device installed in the HCEs at SEGS VI – X, operational problems that caused bowing, and HCE installation procedures. The HR is no longer part of the HCEs provided by Solel.

Based on these factors, it is very possible that future plants will have substantially lower HCE failure rates than those currently found at the SEGS plants. The SunLab assumption of a 2% failure rate assumes that current approaches for reducing failures are successful. S&L believes that this is an aggressive assumption that cannot be assured for future plants without the field data to verify the failure rate reduction. Using the current replacement rate occurring at all the SEGS plants, with step reductions in the replacement rate, reflects the current conditions and allows for the aforementioned improvements to reduce the replacement rate.

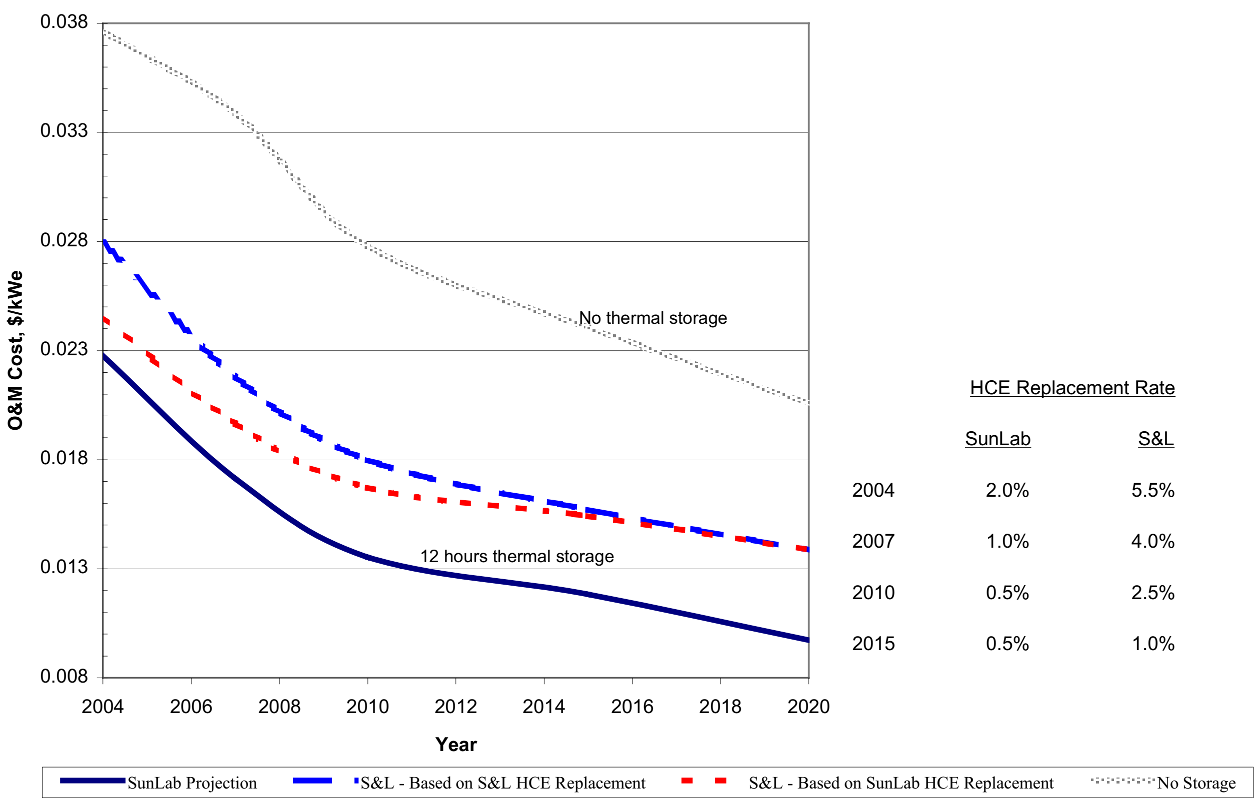
Additional development of the HCE will likely be necessary to achieve the future receiver reliability goals. The current glass-to-metal seal is one of the more expensive elements and the key failure point of the current receiver design. The current seal design, known as a Housekeeper seal, relies on a sharp metal point being inserted into a glass bead. Failures occur when concentrated light focuses on seal and the differential expansion between the glass and metal causes the failure of the seal. New designs are currently under investigation that attempt to improve the match between the coefficient of thermal expansion of the metal and glass. Kramer Junction is currently testing a new design, UVAC2, with a revised internal shield.

To achieve the SunLab projected replacement rates, the reliability of the HCE will have to improve significantly. Table 4-14 and Figure 4-5 compare the O&M costs and illustrate the impact of the HCE replacement rate. The O&M costs without thermal storage are included for informational purposes.

Table 4-14 — Comparison of O&M Cost Estimates ($/kWh$_e$): SunLab vs. S&L

	2004	2007	2010	2015	2020
SunLab	0.0228	0.0171	0.0135	0.0118	0.0097
S&L – S&L HCE Replacement	0.0280	0.0218	0.0180	0.0157	0.0139
S&L – SunLab HCE Replacement	0.0246	0.0197	0.0167	0.0154	0.0139
S&L – No Storage	0.0377	0.0339	0.0278	0.0241	0.0206

Figure 4-5 — Levelized O&M Cost Comparison



The reduction in O&M cost is primarily a result of the increase in plant size and the increase in annual plant capacity factor. The plant capacity increases directly as a result of the increases in thermal storage. Increasing the size (MWe) and capacity factor of the power plant incurs minimal increase in the fixed O&M expenses ($/year).

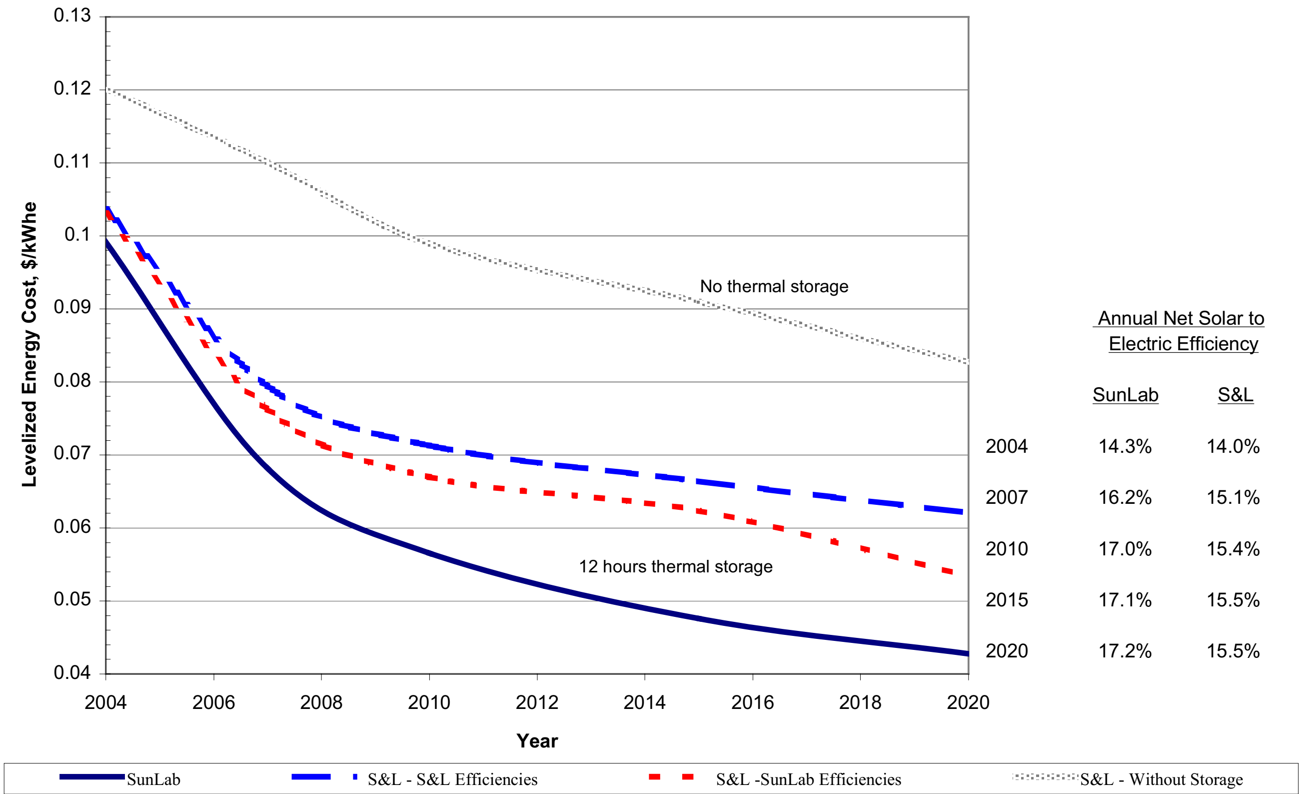
4.4 LEVELIZED ENERGY COSTS

Table 4-15 and Figure 4-6 below illustrate the SunLab projected levelized energy cost ($/kWhe) compared to the S&L values. The figure also shows the levelized energy cost based on achieving the annual net efficiencies projected by SunLab. For comparison, the estimated levelized energy cost for the trough plants without thermal storage is included in Figure 4-6 to underscore the importance of thermal storage in the reduction of the levelized energy cost.

Table 4-15 — Comparison of Levelized Energy Cost Estimates ($/kWhe): SunLab vs. S&L

	2004	2007	2010	2015	2020
SunLab	0.0991	0.0681	0.0566	0.0476	0.0428
S&L – S&L Efficiencies	0.1037	0.0795	0.0713	0.0664	0.0621
S&L – SunLab Efficiencies	0.1031	0.0763	0.0670	0.0624	0.0534
S&L – No Storage	0.1201	0.1100	0.0989	0.0910	0.0826

Figure 4-6 — Levelized Energy Costs



The curves highlight the impact of the annual net efficiencies on the levelized energy costs. The curves also indicate that additional cost reductions above and beyond the more conservative S&L values, due to technology improvements, reduced HCE replacement rates, and increased deployment rates, will result in further convergence of the levelized energy costs toward the projected SunLab values.

Figure 4-7 shows the levelized energy cost for the SunLab technology forecasts with a breakdown that shows the source of the cost reduction from plant scale-up, technology R&D, and cost reduction through learning. Of the projected cost reduction in 2020, plant scale-up is projected to provide 20% of the total cost reduction, technology development will provide over half of the cost reduction at 54%, and production volume and competition will provide approximately 26% of the cost reduction.

Figure 4-7 — Breakdown of LEC Cost Reduction (Scale-up, R&D, Volume Production)

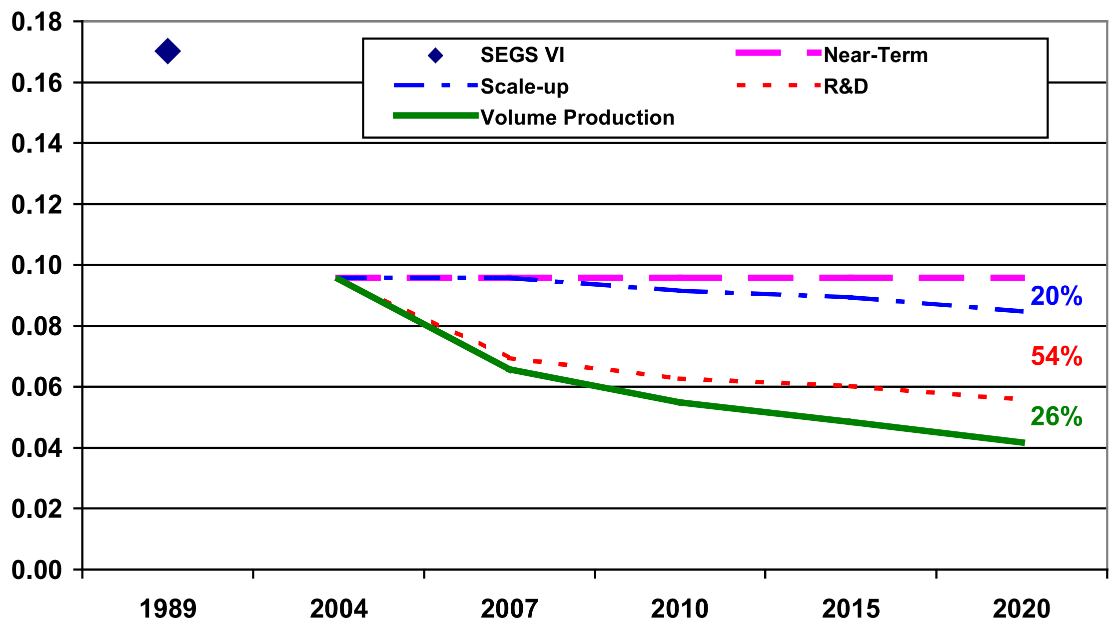
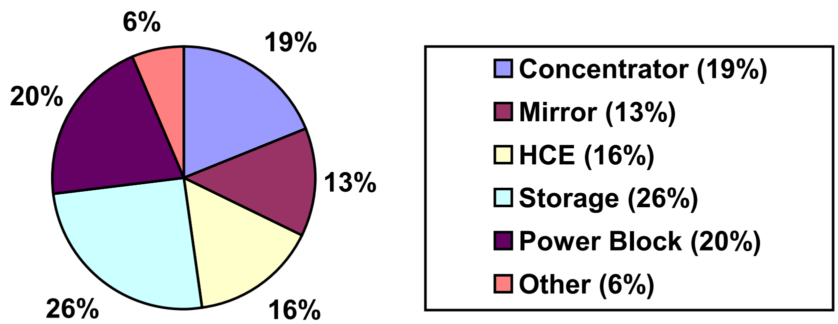


Figure 4-8 below shows the importance of the five major cost components in Section 4.3 in reducing the LEC.

Figure 4-8 — Breakdown of LEC Cost Reduction (by Major Cost Component)



The impact of levelized cost of energy for tax credit is shown in Table 4-16. The difference between 10% tax credit and no tax credit is about 8% in 2020.

Table 4-16 – Impact of Tax Credit on Levelized Cost of Energy

				Levelized Energy Cost, $/kWhe, by Case				
				Near Term		Mid Term		Long Term
				Solar Tres USA	Solar 50	Solar 100	Solar 200	Solar 220
	IRR	% Debt	DSCR	2004	2006	2010	1015	2020
10 % Tax Credit	12.12%	59.90%	1.35	0.0991	0.0681	0.0566	0.0476	0.0428
No Tax Credit	12.12%	66.50%	1.35	0.1075	0.0737	0.0613	0.0541	0.0461

4.5 TECHNOLOGY STEP CHANGES AND COMPARISON

The following tables provide a summary of the major 2004 through 2020 technology changes and a comparison of the SunLab and S&L values.

Table 4-17 — Current (SEGS VI) to Trough 100 – 2004

		Trough 100 – 2004		
	Current	Sun Lab	S&L	Basis
Plant Size	30 MWe	100 MWe		
Field Aperture Area	188,000 m^2	1,120,480 m^2	1,138,709 m^2	Greater aperture area required for S&L estimate due to lower estimated annual efficiency
Thermal Storage	0 hours	12 hours	2-tank Indirect	Based on Nexant design being proposed for 50-MW trough project in Spain
Annual Plant Capacity	22.2%	53.5%		Capacity increased by thermal storage.
Heat Transfer Fluid	VP-1 oil	VP-1 oil		
Storage Media	None	Solar Salt		Technically proven at Solar 2
Operating Temperature	391°C	391°C		
Receiver	Luz	Solel		Solel 2nd Generation UVAC HCE

		Trough 100 – 2004		
	Current	**Sun Lab**	**S&L**	**Basis**
Coating	Cermet	UVAC2		Second-generation Solel UVAC cermet coating currently being field tested at KJCOC
Collector	LS-2	LS-2+		Updated version of LS-2 collector based on discussions with Duke Solar and KJCOC
Annual solar-to-electric efficiency	**10.6%**	**14.3%**	**14.0%**	S&L used lower receiver efficiency than SunLab based on current data
Solar Field Optical Efficiency:	53.3%	56.7%	56.7%	The incident angle modifier improves slightly in plants with thermal storage, because more energy is collected early in the day. The increase in envelope transmittance is based on improved anti-reflective coatings on inside and outside of the receiver glass envelope. The new value is based on property testing of Solel UVAC HCE by Sandia National Labs. SunLab increase of absorption based on property measurement of second-generation UVAC receiver (SPF, 2001). Mirror and envelope cleanlinesses of 95% and 98.5% are reasonable based on Kramer Junction experience.
IAM, end loss	89.9%	91%	91%	
Mirror reflectivity	93.5%	93.5%	93.5%	
Envelope transmittance	92.5%	96.5%	96.5%	
Solar absorption	92%	94.4%	94.4%	
Mirror cleanliness	93.1%	95%	95%	
Envelope cleanliness	98%	98.5%	98.5%	
Dumped energy	99.9%	95.6%	95.6%	
Concentrator length	50 meters	50 meters	50 meters	
Receiver Efficiency:	72.9%	85.9%	84.3%	Latest Solel UVAC selective coating. Solel testing at SPF showed an emittance of 0.091, however field testing required. S&L used 0.10 based on the test data
Thermal emittance	0.135 at 400°C	0.091 at 400°C	0.100 at 400°C	
Piping Thermal Losses	96.1%	96.5%	96.5%	
Thermal Storage Thermal Losses	NA	99.1%	99.1%	Based on thermal losses at Solar Two and detailed thermal storage design model.
Gross steam cycle efficiency	35.1%	37.0%	37.0%	Verified by SEGS IX ABB Heat Balances HTDG 582395, Sheets 1-7 (in LUZ International Limited 1990) The addition of thermal storage reduces part load operation, reduces the percent of energy used for startup, and eliminates losses due to minimum turbine load.
Turbine Design	37.5%	37.5%	37.5%	
Part Load	98%	99.5%	99.5%	
Startup	96.9%	99.2%	99.2%	
Turbine Minimum	98.5%	100%	100%	

	Current	Trough 100 – 2004		Basis
		Sun Lab	S&L	
Parasitics	82.4%	87.7%	87.7%	Conversion from Flex hoses to ball joint assemblies. Reduces pressure drop in collector loop. Demonstrated in KJCOC O&M cost reduction study. The fixed station load is spread over higher plant capacity factor. For a larger plant the station load is a smaller % of total load. SEGS VI parasitics included control building and Maintenance shop at SEGS VII.
Solar Field	0.23%	0.20%	0.20%	
HTF Cold Pumps	5.90%	3.75%	3.75%	
HTF Hot Pumps	0.00%	1.06%	1.06%	
HTF Freeze Protection	1.52%	1.16%	1.16%	
Backup Heater/Boiler	0.00%	0.00%	0.00%	
Hotel Load (24 hr)	3.67%	1.62%	1.62%	
Balance-of-Plant	4.36%	2.73%	2.73%	
Cooling Towers	1.89%	1.81%	1.81%	
Plant-wide Availability	98.0%	94.0%	94.0%	Reasonable based on Kramer Junction experience.

Table 4-18 — Trough 100 – 2004 (Near-Term Case) to Trough 100 – 2007

	Trough 100 - 2004	Trough 100 - 2007		Basis
		Sun Lab	S&L	
Plant Size	100 MWe	100 MWe		
Field Aperture Area	1,120,480 m^2	1,037,760 m^2	1,108,830 m^2	Greater aperture area required for S&L estimate due to lower estimated annual efficiency
Thermal Storage	12 hours 2-tank Indirect	12 hours Thermocline Direct		Next generation of storage under development at SunLab. Uses single tank storage system.
Annual Plant Capacity	53.5%	56.2%		
Heat Transfer Fluid	VP-1 oil	Hitec XL nitrate salt		Freezes at 120°C, must keep field at 150C minimum temperature. Cold salt from storage used for night time freeze protection.
Storage Media	Solar Salt	HitecXL, rock & sand filler		Thermal cycling testing of rock & sand filler at SNL
Operating Temperature	293-400°C	293-450°C		Salt HTF allows operating temperature to be increased.
Receiver	Solel	Advanced 1		Next generation receiver design

	Trough 100 - 2004	Trough 100 - 2007		Basis
		Sun Lab	**S&L**	
Coating	UVAC2	Advanced 1		Advanced cermet either by Solel or other source
Collector	LS-2+	LS-3+		Assumes the larger aperture of the LS-3 and 1.5x the length. Optical performance is assumed to be similar to the LS-2 collector. This is the EuroTrough or equivalent.
Annual solar-to-electric efficiency	**14.2%**	**16.1%**	**15.1%**	
Solar Field Optical Efficiency:	56.4%	57.9%	57.0%	The incident angle modifier improves slightly with longer collector. Mirror cleanliness of 95% is reasonable based on Kramer Junction experience. SunLab increase in envelope transmittance based on Sandia test data. SunLab assumed increase in absorption based on selective coating modeling at NREL.
IAM, end loss	91%	91.8%	91.8%	
Mirror reflectivity	93.5%	93.5%	93.5%	
Envelope transmittance	96.5%	97%	96.5%	
Solar absorption	94.4%	96%	94.4%	
Mirror cleanliness	95%	95%	95%	
Envelope cleanliness	98.5%	98.5%	98.5%	
Dumped energy	95.6%	95.2%	95.6%	
Concentrator length	50 meters	150 meters	150 meters	
Receiver Efficiency:	85.9%	86.2%	82.3%	SunLab decrease in emittance based on SunLab selective coating modeling.
Thermal emittance	0.091 at 400°C	0.070 at 400°C	0.100 at 400°C	
Gross steam cycle efficiency	37.0%	39.0%	39.0%	Reasonable based on increase of temperature from 400°C to 450°C. GEPerf computer program check used to verify increase.
Turbine Design	37.5%	39.4%	39.4%	
Part Load	99.5%	99.7%	99.7%	
Startup	99.2%	99.2%	99.2%	
Turbine Minimum	100%	100.0%	100.0%	

	Trough 100 - 2004	Trough 100 - 2007		Basis
		Sun Lab	S&L	
Parasitics	87.7%	91.1%	91.1%	SunLab parasitics reduction based on replacement of VP-1 with HitecXL in the solar field and elimination of need to run two sets of pumps in the indirect storage system. The Nexant piping model calculates a 65% reduction in HTF pumping parasitics with molten-salt.
Solar Field	0.20%	0.13%	0.13%	
HTF Cold Pumps	3.75%	1.75%	1.75%	
HTF Hot Pumps	1.06%	0.53%	0.53%	
HTF Freeze Protection	1.16%	1.06%	1.06%	
Backup Heater/Boiler	0.00%	0.00%	0.00%	
Hotel Load (24 hr)	1.62%	1.60%	1.60%	
Balance of Plant	2.73%	2.05%	2.05%	
Cooling Towers	1.81%	1.81%	1.81%	
Plant-wide Availability	94.0%	94.0%	94.0%	

Table 4-19 — Trough 100 – 2007 (mid-Term) to Trough 150 – 2010

	Trough 100 - 2007	Trough 150 - 2010		Basis
		Sun Lab	S&L	
Plant Size	100 MWe	150 MWe		
Field Aperture Area	1,120,480 m^2	1,477,680 m^2	1,632,301 m^2	Greater aperture area required for S&L estimate due to lower estimated annual efficiency
Thermal Storage	12 hours 2-tank Direct	12 hours Thermocline Direct		
Annual Plant Capacity	56.2%	56.2%		
Heat Transfer Fluid	HitecXL	HitecXL nitrate salt		Testing currently in progress to make sure Hitec XL can be used up to 500^{o}C.
Storage Media	HitecXL, rock & sand filler	HitecXL, rock & sand filler		Thermal cycling testing of rock & sand filler at SNL
Operating Temperature	450^{o}C	500^{o}C		
Receiver	Advanced 1	Advanced 2		Higher temperature capability
Coating	Advanced 1	Advanced 2		Same thermal & optical properties but able to operate to 500^{o}C

	Trough 100 - 2007	Trough 150 - 2010		Basis
		Sun Lab	S&L	
Collector	LS-3+	Next Generation		New design based on use of front surface reflectors and structural mirror facets.
Annual solar-to-electric efficiency	**14.2%**	**17.0%**	**15.4%**	
Solar Field Optical Efficiency:	57.9%	59.8%	57.0%	S&L estimate mirror cleanliness of 95% based on Kramer Junction experience. SunLab mirror reflectivity increase from 0.935 to 0.95 based on use of front Surface mirror with anti-soiling coating to reduce mirror soiling rate, mirror cleanliness from 0.95 to 0.96.
IAM, end loss	91.8%	91.8%	91.8%	
Mirror reflectivity	93.5%	95%	93.5%	
Envelope transmittance	97.0%	97.0%	96.5%	
Solar absorption	96%	96%	94.4%	
Mirror cleanliness	95%	96%	95%	
Envelope cleanliness	98.5%	98.5%	98.5%	
Dumped energy	95.2%	95.2%	95.2%	
Concentrator length	150 meters	150 meters	150 meters	
Receiver Efficiency:	86.2%	85.2%	81.0%	S&L assumes no improvement over current demonstrated Solel UVAC receiver, except higher temperature capability to 500°C.
Thermal emittance	0.070 at 400°C	0.070 at 400°C	0.100 at 400°C	
Gross steam cycle efficiency	39.0%	40.0%	40.0%	GEPerf computer program check used to verify increase.
Turbine Design	39.4%	40.5%	40.5%	
Part Load	99.7%	99.7%	99.7%	
Startup	99.2%	99.2%	99.2%	
Turbine Minimum	100.0%	100.0%	100.0%	

	Trough 100 - 2007	Trough 150 - 2010		Basis
		Sun Lab	S&L	
Parasitics	91.1%	91.8%	91.8%	Reduction in parasitics is reasonable.
Solar Field	0.13%	0.13%	0.13%	SunLab reduction in HTF parasitics based on increasing operating temperature to 500°C.
HTF Cold Pumps	1.75%	1.33%	1.33%	
HTF Hot Pumps	0.53%	0.42%	0.42%	BOP parasitics reduced due to larger plant size.
HTF Freeze Protection	1.06%	1.02%	1.02%	
Backup Heater/Boiler	0.00%	0.00%	0.00%	
Hotel Load (24 hr)	1.60%	1.62%	1.62%	
Balance of Plant	2.05%	1.91%	1.91%	
Cooling Towers	1.81%	1.81%	1.81%	
Plant-wide Availability	94.0%	94.0%	94.0%	

Table 4-20 — Trough 150 – 2010 to Trough 200 – 2015

	Trough 150 -	Trough 200 - 2015		
	2010	Sun Lab	S&L	Basis
Plant Size	150 MWe	200 MWe		
Field Aperture Area	1,477,680 m^2	1,955,200 m^2	2,161,485 m^2	Greater aperture area required for S&L estimate due to lower estimated annual efficiency
Thermal Storage	12 hours Thermocline Direct	12 hours Thermocline Direct		
Annual Plant Capacity	56.2%	56.2%		
Heat Transfer Fluid	Hitec XL	Hitec XL		
Operating Temperature	500°C	500°C		
Receiver	Advanced 2	Advanced 2		
Coating	Advanced 2	Advanced 2		
Collector	Next Generation	Next Generation		
Annual solar-to-electric efficiency	**17.0%**	**17.1%**	**15.4%**	

	Trough 150 -	Trough 200 - 2015		
	2010	Sun Lab	S&L	Basis
Solar Field Optical Efficiency:	59.8%	60.2%	57.0%	SunLab estimate assumes anti-soiling treatment added to receiver envelope to improve cleanliness. Sargent & Lundy assumes no improvement from earlier case.
IAM, end loss	91.8%	91.8%	91.8%	
Mirror reflectivity	95%	95%	93.5%	
Envelope transmittance	97.0%	97.0%	96.5%	
Solar absorption	96%	96%	94.4%	
Mirror cleanliness	96%	96%	95%	
Envelope cleanliness	98.5%	99%	98.5%	
Dumped energy	95.2%	95.2%	95.2%	
Concentrator length	150 meters	150 meters	150 meters	
Receiver Efficiency:	85.2%	85.3%	81.0%	No change for SunLab case, S&L assumes current UVAC design.
Thermal emittance	0.070 at 400°C	0.070 at 400°C	0.100 at 400°C	
Gross steam cycle efficiency	40.0%	40.0%	40.0%	
Turbine Design	40.5%	40.5%	40.5%	
Part Load	99.7%	99.7%	99.7%	
Startup	99.2%	99.2%	99.2%	
Turbine Minimum	100.0%	100.0%	100.0%	
Parasitics	91.8%	91.8%	91.8%	
Solar Field	0.13%	0.13%	0.13%	
HTF Cold Pumps	1.33%	1.32%	1.32%	
HTF Hot Pumps	0.42%	0.42%	0.42%	
HTF Freeze Protection	1.02%	1.01%	1.01%	
Backup Heater/Boiler	0.00%	0.00%	0.00%	
Hotel Load (24 hr)	1.62%	1.62%	1.62%	
Balance of Plant	1.91%	1.91%	1.91%	
Cooling Towers	1.81%	1.81%	1.81%	
Plant-wide Availability	94.0%	94.0%	94.0%	

Table 4-21 — Trough 200 – 2015 to Trough 400 – 2020

	Trough 200 - 2015	Trough 400 - 2020		
		Sun Lab	**S&L**	**Basis**
Plant Size	200 MWe	400 MWe		
Field Aperture Area	1,955,200 m^2	3,910,400 m^2	4,348,931 m^2	Greater aperture area required for S&L estimate due to lower estimated annual efficiency
Thermal Storage	12 hours Thermocline Direct	12 hours Thermocline Direct		
Annual Plant Capacity	56.2%	56.5%		
Heat Transfer Fluid	Hitec XL	Hitec XL		
Operating Temperature	500°C	500°C		
Receiver	Advanced 2	Advanced 2		
Coating	Advanced 2	Advanced 2		
Collector	Next Generation	Advanced Generation 1		
Annual solar-to-electric efficiency	**17.1%**	**17.2%**	**15.5%**	
Solar Field Optical Efficiency:	59.8%	60.2%	57.0%	S&L & SunLab estimates assume no change from earlier case.
IAM, end loss	91.8%	91.8%	91.8%	
Mirror reflectivity	95%	95%	93.5%	
Envelope transmittance	97.0%	97.0%	96.5%	
Solar absorption	96%	96%	94.4%	
Mirror cleanliness	96%	96%	95%	
Envelope cleanliness	98.5%	99%	98.5%	
Dumped energy	95.2%	95.2%	95.2%	
Concentrator length	150 meters	150 meters	150 meters	
Receiver Efficiency:	85.3%	85.3%	81%	
Thermal emittance	0.070 at 400°C	0.070 at 400°C	0.100 at 400°C	

	Trough 200 - 2015	Trough 400 - 2020		Basis
		Sun Lab	S&L	
Gross steam cycle efficiency	40.0%	40.0%	40.0%	GEPerf computer program check used to verify increase.
Turbine Design	40.5%	40.5%	40.5%	
Part Load	99.7%	99.7%	99.7%	
Startup	99.2%	99.2%	99.2%	
Turbine Minimum	100.0%	100.0%	100.0%	
Parasitics	91.8%	92.4%	92.4%	SunLab parasitics assume increase in HTF pumping parasitics for larger size solar field and a reduction in hotel load based on scale-up in size to 400 MWe
Solar Field	0.13%	0.13%	0.13%	
HTF Cold Pumps	1.32%	1.45%	1.45%	
HTF Hot Pumps	0.42%	0.43%	0.43%	
HTF Freeze Protection	1.01%	1.01%	1.01%	
Backup Heater/Boiler	0.00%	0.00%	0.00%	
Hotel Load (24 hr)	1.62%	0.90%	0.90%	
Balance of Plant	1.91%	1.92%	1.92%	
Cooling Towers	1.81%	1.81%	1.81%	
Plant-wide Availability	94.0%	94.0%	94.0%	

4.6 RISK ASSESSMENT FOR TROUGH TECHNOLOGY

This section provides an overview and assessment of the risks associated with attaining competitive commercialization for the parabolic trough technology on a short-term, mid-term, and long-term basis. Competitiveness is measured by the levelized energy cost (LEC), expressed as $/kWh, consisting of two elements: total investment cost and operation and maintenance (O&M) cost.

The major total investment cost drivers of the trough plant are the solar field, power block, and thermal storage, which account for approximately 90% of the total costs (based on 12 hours of thermal storage). Also, the net annual solar-to-electric efficiency has a significant impact on the cost of a trough plant. For every one percentage point improvement in the net efficiency, the cost is reduced by approximately 7%.

Total cost reductions occur from technical improvements, increase in plant size (scaling), and volume production (learning curves). All three are dependent on deployment of the technology. Deployment provides a means for continued research in technology improvements, cost reductions due to increased production, and economy of scale from constructing larger plants.

The second element of the levelized energy cost is the O&M costs. For the trough plant, O&M costs represent 25% or more of the LEC.

As such, the focus of the risk assessment covers the following main categories:

- Deployment
- Net Annual Solar-to-Electric Efficiency
- Total Investment Cost
- Operation and Maintenance

4.6.1 Deployment

Market expansion of trough technology will require incentives to reach market competitiveness. Numerous potential incentives exist, such as: environmental (CO_2 emission credits), favorable tax credits, favorable peak energy tariff, premium consumer pricing, loan guarantees, low interest loans, and grants. Analysis of incentives required to reach market acceptance is not within the scope of this report.

4.6.1.1 Near Term (2004)

The SunLab near-term deployment projection is one identical 100-MW plant per year in the years 2004 through 2006 (three plants total).

The actual strategy employed by the plant suppliers can be significantly diverse, with more emphasis on near-term cost reduction with a minimum of risk. The trough plant suppliers may opt to provide multiple plants in the 50 MWe, to 100 MWe size with no thermal storage but with a supplemental steam generator, replicating the proven technology of the existing SEGS plants. The suppliers can rely more on initial production volume to reduce costs as opposed to efficiency and technology improvements and scale-up factors. Minimizing or eliminating thermal storage, with its current elevated cost, appreciably reduces the total direct cost of the plant. Without thermal storage, the direct capital cost is approximately 50% less for the 100-MW plant deployed in the 2004–2006 time frame. However, due to the lower annual MWh generation, the LEC ($/MWh) is approximately 20% higher than for a plant with 12 hours of thermal storage.

4.6.1.2 Mid Term (2010)

The SunLab mid-term deployment projection is six 100-MW plants and one 150-MW plant with improved technology being deployed in the years 2007 through 2010.

4.6.1.3 Long Term (2020)

The SunLab long-term deployment projection is eight 150-MW plants with improved technology being deployed in the years 2010 through 2014; twelve advanced technology 200-MW plants in the years 2015 through 2020; and one 400-MW advanced technology plant in 2020. The SunLab total long-term deployment is 4,900 MW of installed capacity.

4.6.2 Net Annual Solar-to-Electric Efficiency

4.6.2.1 Near Term (2004)

The SunLab projected near-term net annual solar-to-electric efficiency is 14.3%, an improvement of 3.7 percentage points from the SEGS VI 10.6% efficiency. The increased efficiency is mainly attributable to improved receiver optical and thermal emittance properties. The demonstrated improvements are the following:

- Significant improvements in selective coatings have occurred since the last SEGS plant was built. The solar absorptance of the cermet tubes used at SEGS VI was approximately 91.5%. According to test data (SPF 2001), the Solel UVAC receiver tubes have a solar weighted absorptance of 94.4%.
- Anti reflective coatings for glass have been improved in the last 10 years to improve durability. The new receiver tubes have anti-reflective coatings that deliver solar transmittances of 96.5%, compared with earlier coating that only allowed 92.5%.
- SEGS VI had a combination of black chrome and the original generation of Luz Cermet receiver tubes. The average thermal emittance of these tubes is approximately 20% greater at 350°C. The UVAC receiver first installed at SEGS VI had a thermal emittance of 14% at 400°C. According to tests performed for Solel, the second-generation UVAC receiver had a thermal emittance of about 9% at 400°C

There is a low risk of achieving the near-term net annual solar-to-electric efficiency of 14.3%, since the receiver properties that the improvement is dependent on have been demonstrated either by operating experience at the SEGS plants or from test data.

4.6.3 Mid Term (2010)

The SunLab projected mid-term net annual solar-to-electric efficiency is 17.0%, an improvement of 2.7 percentage points from the near-term projected efficiency of 14.3%. This improvement is mainly attributable to the following:

- Second-generation advanced receiver with an optical design point efficiency of 79.1% (compared to near-term 75%) as a result of a solar absorptance of 96% (compared to near-term 94.4%) and mirror reflectivity of 95% (compared to near-term 93.5%).
- Improved steam turbine cycle efficiency of 3 percentage points as a result of increasing the solar field operating temperature to 500°C.

There is a high risk of achieving the mid-term net annual solar-to-electric efficiency of 17.0% based on the following considerations:

- The optical efficiency improvement is based on two steps of receiver advancements, an advanced heat collection element (HCE) coating for the projected 500°C operating temperature. Alternate HCE designs are under various stages of development that indicate lower cost than the Solel UVAC HCE, but at reduced efficiency levels. Reduced HCE efficiency will result in a lower net annual solar-to-electric efficiency.
- While there are no steam turbine technological risks in achieving the improved efficiency, the type of heat transfer fluid (HTF) will have to be changed to obtain the 500°C inlet steam temperature. The SunLab projections assume a nitrate salt HTF with an upper operating range of 500°C. Alternate HTF development will be required since use of nitrate salt has not been demonstrated for the trough technology.
- A direct thermocline thermal storage system is assumed for the mid-term case. At the present time, preliminary assessments have been made on the potential impact that a thermocline storage system might have on the annual performance of the plant and more detailed analyses and research are required. The current ball joints will not work with the high-temperature salt HFT, and flexhose and ball joint sealing options have to be researched and developed. Various thermal storage options are in the early stages of development.

A mid-term net annual solar-to-electric efficiency in the 15.4% range represents a low risk by limiting the technology improvements to currently demonstrated or tested improvements.

The reduction in efficiency from the projected 17.0% to 15.4% results in an increase in the mid-term levelized energy cost of approximately $0.0045/kWhe.

4.6.3.1 Long Term (2020)

The SunLab projected long-term net annual solar-to-electric efficiency is 17.2%, an improvement of 0.2 percentage points from the mid-term projected efficiency of 17.0%. This modest improvement is mainly attributable to operational improvements to reduce thermal losses and reducing the amount of dust on the envelope.

There is a high risk of achieving the long-term net annual solar-to-electric efficiency of 17.2% due to the mid-term risks discussed previously. However, the risk is greatly reduced if the trough technology is successfully deployed to the extent that the competitive market prompts research and development of technological advances.

4.6.4 Total Investment Cost

The major cost contributors in total investment cost of a parabolic trough solar plant with thermal storage are the solar collector field (53%), thermal storage system (23%), and the power block (14%).

In combination with thermal storage, increased annual net efficiency, and reduced equipment cost via technology advancements, competition and deployment are the primary elements in reducing the long-term cost of the trough plant.

4.6.4.1 Near Term (2004)

The SunLab projected near-term total investment cost, with the exception of the thermal storage, is based on actual values from the SEGS plants. Costs for components such as the HCE and mirrors are based on current pricing of replacement parts for the SEGS plants.

The near-term indirect two-tank thermal storage system is based on cost estimates from detailed design drawings and material takeoffs developed by Nextant. The technological risk using the two-tank molten-salt storage system is low based on the successful utilization at the Solar Two plant.

Estimated costs based on the SOAPP program indicate that the SunLab projected capital costs for the power block are conservative (on the high side), approximately $50/kW higher than estimated by the SOAPP program. The SunLab power block cost estimates are based on a 1990 ABB quotation for a 100-MW steam turbine. The ABB quotation was escalated and scaled-up for the larger sizes. The SunLab power block cost estimates are based on dated information and the escalation and scale-up factors add to the uncertainty of the data with respect to current pricing. Equipment prices in the SOAPP program reflect 2001 actual costs. Since the SOAPP pricing is current, the SOAPP-generated costs are more characteristic of current power block costs.

Based on the above considerations, there is a low risk of achieving the near-term total investment cost.

4.6.4.2 Mid Term (2010)

The SunLab projected mid-term total investment cost indicates a total cost of $2,876/kWe, a reduction of $1,983/kWe from the near-term projected cost of $4,859/kWe, mainly attributable to the following:

- An increase in the plant size from 100 MW to 150 MW, which reduces the $/kWe cost by virtue of the larger kWe size.
- Reduced cost of solar collection system components, such as HCE and mirrors, of approximately 35% as a result of technological advances, competition, and production volume.
- Reduction of the thermal storage capital cost from the near-term $958/kWe to $383/kWe by using a direct thermocline thermal storage system.

There is a high risk of achieving the SunLab projected mid-term total investment cost of $2,876/kWe, based on the following considerations:

- The SunLab projected reduced cost of solar collection system components, such as HCE and mirrors, is based on six 100-MW plants and one 150-MW plant with improved technology being deployed in the years 2007 through 2010. Market expansion of trough technology will require incentives to reach the projected level of deployment.
- The SunLab projected mid-term net annual solar-to-electric efficiency is 17.0%, an improvement of 2.7 percentage points from the near-term projected efficiency of 14.3%. The solar field size, and thus the solar field cost, is directly proportional to the net annual solar-to-electric efficiency of a trough plant. As previously discussed, there is a high risk of achieving the mid-term net annual solar-to-electric efficiency of 17.0%. Using a mid-term net annual solar-to-electric efficiency in the 15.4% range, which represents a lower risk by limiting the technology improvements to currently demonstrated or tested improvements, results in a 8% decrease in the solar field size compared to 19% decrease for a 17.0% efficiency.
- The SunLab projected mid-term direct thermocline system with HitecXL (ternary) solar salt as the storage media and heat transfer fluid (HTF), allowing the solar field to be operated to higher outlet temperatures (500°C). No thermal storage technology has been commercially demonstrated for the higher solar field operating temperatures. Additional development is required for the thermocline system. In addition to the development of a thermocline system, an advanced HCE will be required to obtain the 500°C HTF operating temperature.

4.6.4.3 Long Term (2020)

The SunLab projected long-term total investment cost indicates a total cost of $2,221/kWe, a reduction of $655/kWe from the mid-term projected cost of $2,876/kWe, mainly attributable to the following:

- An increase in the plant sizes from the 100–150-MW range to the 200–400-MW range, which reduces the $/kWe cost by virtue of the larger kWe size.
- Reduced cost of solar collection system components from mid-term costs, such as HCE and mirrors, of approximately 25% as a result of technological advances, competition, and production volume.

There is a high risk of achieving the SunLab projected long-term total investment cost due to the mid-term risks discussed previously. However, the risk is mitigated if the trough technology is successfully deployed to the extent that the competitive market prompts research and development of technological advances and plant sizes in the 200–400-MW range.

4.6.5 Operation and Maintenance (O&M) Costs

The SunLab O&M estimate is based largely on the experience at the KJC Operating Company SEGS plants. The model assumes a stand-alone trough power plant (as opposed to the five co-located plants at Kramer Junction) and adjusts costs depending on the size of the solar field and total electric generation per year. KJC Operating Company provided proprietary information on the last five years of operation.

The major cost contributors for O&M costs are as follows:

- Solar field replacement of the heat collection elements (HCE)
- Staffing

The staffing is a fixed cost, and the SunLab projected manpower requirements are reasonable based on data from similar-sized power plants.

The industry plan keys on thermal storage to obtain a high capacity factor, which reduces the O&M costs ($/MWh) by obtaining a higher annual MWh generation. The net annual solar-to-electric efficiency has a significant impact on the O&M costs. Increased efficiency reduces the size of the solar field and thus reduces the number of mirror and HCE replacements required.

4.6.5.1 Near Term (2004)

The SunLab projected near-term O&M cost is based on an HCE replacement rate of 2%, a net annual solar-to-electric efficiency of 14.3%, and 12 hours of thermal storage. As previously indicated, there is a low risk of achieving the near-term net annual solar-to-electric efficiency and the technological risk using the two-tank molten-salt storage system is low. However, the HCE replacement rate of 2% is not consistent with the average actual HCE replacement rate of 5.5% reported for SEGS III – VII for the period 1997–2001. Using the average replacement rate of 5.5% increases the levelized O&M cost by approximately $0.004/kWhe, an increase of 17%.

There is a high risk of achieving the SunLab projected near-term O&M cost since the SunLab assumption of a 2% HCE replacement rate assumes that current approaches for reducing failures are successful. S&L believes this is an aggressive assumption that cannot be assured for future plants without the field data to verify the failure rate reduction. A lower risk would be using a HCE replacement rate of 5.5% and an annual solar-to-electric efficiency of 14.0%

4.6.5.2 Mid Term (2010)

The SunLab projected mid-term O&M cost is based on an HCE replacement rate of 0.5%, a net annual solar-to-electric efficiency of 17%, and 12 hours of thermal storage using a direct thermocline system with HitecXL (ternary) solar salt.

As previously indicated, there is a high risk of achieving the mid-term net annual solar-to-electric efficiency of 17.0% and a mid-term net annual solar-to-electric efficiency in the 15.4% range represents a low risk by limiting the technology improvements to currently demonstrated or tested improvements. Also, the direct thermocline thermal storage system has not been commercially demonstrated for the higher solar field operating temperatures and additional development is required for the thermocline system. In addition to the development of a thermocline system, an advanced HCE will be required to obtain the 500°C HTF operating temperature.

New designs are currently under investigation that attempt to improve the reliability of the HCE. Kramer Junction is currently testing a new design UVAC2 with a revised internal shield. A more conservative replacement rate for the S&L comparison is 2.5%.

There is a high risk of achieving the SunLab projected mid-term O&M cost. A lower risk would be using a HCE replacement rate of 2.5% and an annual solar-to-electric efficiency of 15.4%.

4.6.5.3 Long Term (2020)

The SunLab projected long-term O&M cost is based on an HCE replacement rate of 0.5%, a net annual solar-to-electric efficiency of 17.2%, and 12 hours of thermal storage using a direct thermocline system with HitecXL (ternary) solar salt. The projected long-term plant is basically the same configuration as the projected mid-term plant with the reduction in O&M cost primarily as a result of the increase in plant size to 400 MW. As such, there is the same high risk of achieving the SunLab projected O&M cost.

4.7 COST SENSITIVITIES

In this section, variations in the inputs for levelized energy costs are shown to illustrate the sensitivity of energy calculated cost to variations. The sensitivity analysis revealed that the impact on the LEC of the various scenarios are basically the same for both trough and tower technologies. The base case for the sensitivity analysis for the trough in 2020 is 400 MW with a capital cost of $3,204 per kW and annual O&M costs of $14,129, as is shown in Table 4-22. The tower base case is shown for reference.

Table 4-22 — S&L Base Case for the Year 2020

	Trough	Tower
Year	2020	2020
Capacity, MWe	400	200
Capacity Factor,	56.2%	72.9%
Capital Cost, $/kW	$3,220	$3,591
Annual O&M Cost, $k	$14,129	$9,132
LEC, $/kWh	$0.0621	$0.0547
Economic Life	30 yrs	
General Inflation	2.5 %	
Equity Rate of Return	14%	
Cost of Construction	7%	
Construction Duration	1 yr.	
Investment Tax Credit	10%	
Taxes	40.2%	
Depreciable Life	5 yrs.	

	Trough	Tower
IRR	14%	
DSCR	1.35	

4.7.1 Depreciable Life

The tax depreciation allowances for renewable energy provide a favorable 5-year depreciable life. The Modified Accelerated Cost Recovery System (MACRS) defined depreciation schedules for 5, 10, and 15 years. If the tax laws are changed or reinterpreted, the variation in LEC in 2020 is shown below.

Table 4-23 — Effect of Depreciable Life on Levelized Energy Cost

Depreciable Life (years)	LEC in 2020	
	$/kWh	% difference
5	$0.0621	Base Case
10	$0.0658	6.1%
15	$0.0698	12.5%

4.7.2 Investment Tax Credits

The investment tax credits have a major impact on the economic feasibility of a renewable energy power plant. Current tax law allows a 10% investment tax credit. Future tax laws may allow a larger tax credit such as the 15% before 1985 or disallow investment tax credits. Tax credits from 0% to 15% and Energy Production Tax Credit (PTC) result in the LEC in 2020 to vary as shown below.

Table 4-24 — Effect of Investment Tax Credits on Levelized Energy Cost

Tax Credits (%)	LEC in 2020	
	$/kWh	% difference
0%	$0.0670	7.8%
5%	$0.0645	3.4%
10%	$0.0621	Base Case
15%	$0.0596	-4.0%
PTC of 1.8¢/kWh	$0.0490	-26.9%

4.7.3 Corporate Tax Rate

Corporate tax rates are currently at 35%. State taxes vary depending on the plant location but are assumed to be 8%. The composite base tax rate is 43%. The present Government Administration is currently considering reductions in the corporate tax rate, but the rate can vary depending on the economic conditions at the time. The impact on LEC in 2020 from changes in the tax rate is shown below.

Table 4-25 — Effect of Corporate Tax Rates on Levelized Energy Cost

Corporate Tax Rates			LEC in 2020	
Federal	State	Composite	$/kWh	% Difference
30%	8%	38%	$0.0632	1.9%
35%	8%	43%	$0.0621	Base Case
38%	10%	48%	$0.0610	-1.7%

4.7.4 Inflation

Inflation assumptions do not affect the real dollar levelized energy cost. Increases and decreases in the inflation rate impact the LEC in 2020 as shown below.

Table 4-26 — Effect of Inflation on Levelized Energy Cost

Inflation Rate		LEC in 2020	
Rate	IRR	$/kWh	% difference
1.5%	12.9%	$0.0614	-1.0%
2.5%	14.0%	$0.0621	Base Case
3.5%	15.1%	$0.0627	1.1%

4.7.5 Cost of Capital

Cost of capital for the base case is such that there is an internal rate of return (IRR) of 14%. The impact on LEC in 2020 from a change in the cost of capital is shown in the following table.

Table 4-27 — Effect of Cost of Capital on Levelized Energy Cost

Cost of Capital	LEC in 2020	
IRR	$/kWh	% Difference
13%	$0.0575	-7.3%
14%	$0.0621	Base Case
15%	$0.0668	7.7%

4.7.6 Construction Duration

The plant construction period for the base case is one year based on experience at the SEGS plants. The amount of interest during construction (IDC) is included in the LEC. The impact on LEC in 2020 for construction of two and three years is shown below.

Table 4-28 — Effect of Construction Duration on Levelized Energy Cost

Construction Period (yr)	LEC in 2020	
	$/kWh	% Difference
1	$0.0621	Base Case
2	$0.0655	5.5%
3	$0.069	11.3%

4.7.7 Capital Cost

The variation for increases in capital costs is shown below.

Table 4-29 — Effect of Capital Cost Increases on Levelized Energy Cost

Increase in Capital Cost (%)	LEC in 2020	
	$/kWh	% difference
0%	$0.0621	Base Case
10%	$0.0675	8.8%
20%	$0.0730	17.7%

4.7.8 Annual O&M Cost

The variation for increases in annual O&M costs is shown below

Table 4-30 — Effect of O&M Cost Increase on Levelized Energy Cost

Increase in Annual O&M Cost (%)	LEC in 2020	
	$/kWh	% difference
0%	$0.0621	Base Case
10%	$0.0628	1.2%
20%	$0.0635	2.3%

4.7.9 Ownership

The S&L base case considers ownership by an Independent Power Producer (IPP). An investment by developer/owners and financial institutions would require an IRR of at least 14%. It is more likely that the first several power plants will be owned by utilities. Utilities require a lower IRR and would be more receptive to renewable initiatives. As the industry matures (e.g., capital cost declines and the technology is proven), the IPPs would become involved. There is the potential for private ownership in the early plants, but it would most likely be from manufacturers who could offset the lower IRR with increased sales for solar equipment. The impact of ownership on LEC for 2020 is shown below.

Table 4-31 — Effect of Ownership on Levelized Energy Cost

	IPP	Utility Ownership	Muni
IRR, %	14%	11.5%	0%
Leverage	60/40	50/50	100/0
Cost of Debt	5%	7%	5%
DSCR	1.35	1.74	1.0
LEC, $/kWh	$0.0621	$0.0597	$0.0458
% difference	Base Case	-3.9%	-26.1%