NREL/CP-550-25798

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Prepared for the Proceedings of the ASME Renewable and Advanced Energy Systems for the 21st Century Conference

April 11-14, 1999
Maui, Hawaii

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401-3393
A national laboratory of the U.S. Department of Energy
Operated by Midwest Research Institute
for the U.S. Department of Energy
Under Contract No. DE-AC36-83CH10093

November 1998

Proceedings of the
ASME Renewable and Advanced Energy Systems for the 21st Century Conference
April 11-14, 1999, Maui, Hawaii

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ABSTRACT

Nine parabolic trough power plants located in the California Mojave Desert represent the only commercial development of large-scale solar power plants to date. Although all nine plants continue to operate today, no new solar power plants have been completed since 1990. Over the last several years, the parabolic trough industry has focused much of its efforts on international market opportunities. Although the power market in developing countries appears to offer a number of opportunities for parabolic trough technologies due to high growth and the availability of special financial incentives for renewables, these markets are also plagued with many difficulties for developers. In recent years, there has been some renewed interest in the U.S. domestic power market as a result of an emerging green market and green pricing incentives. Unfortunately, many of these market opportunities and incentives focus on smaller, more modular technologies (such as photovoltaics or wind power), and as a result they tend to exclude or are of minimum long-term benefit to large-scale concentrating solar power technologies. This paper looks at what is necessary for large-scale parabolic trough solar power plants to compete with state-of-the-art fossil power technology in a competitive U.S. power market.

INTRODUCTION

Between 1984 and 1990, Luz International Limited developed, built, and sold nine parabolic trough solar power plants in the California Mojave Desert. These plants, called Solar Electric Generating Stations and referred to as SEGS I–IX, range in size from 14 MWe to 80 MWe and make up a total of 354 MWe of installed generating capacity. Each of these plants was developed as an independent power producer (IPP) project, financed with non-recourse debt, and sold to investor groups. In total, over $1.2 billion was raised to finance these projects. The projects were initially driven by the availability of state and federal investment tax credits. Later, special power purchase contracts available in California played a key role. The SEGS projects are qualifying facilities (QFs) as defined by the 1978 Federal Public Utility Regulatory Policies Act (PURPA) legislation, which enabled the creation of small non-utility renewable and co-generation power plants. PURPA required local utilities to purchase power from QFs. In 1991, Luz declared bankruptcy while in the process of building its tenth plant as a result of delays in the extension of the California solar property tax exemption and the inability to obtain construction financing. Although many factors contributed to the eventual failure of Luz, the primary cause was decreasing energy prices coinciding with the phasing out of state and federal investment tax credits (Lotker, 1991). However, Luz achieved significant reductions in the cost of power from parabolic trough solar power plants, reducing the cost from a reported 24¢/kWh at SEGS I to about 8¢/kWh at SEGS IX.

It is important to note that all of the nine SEGS plants completed continue to operate today. SEGS I is currently in its 14th year of operation. In total, the plants have accumulated 98 plant-years of operation. From an operational perspective, the SEGS plants have been very successful. The plants have demonstrated the industrial nature of the Luz parabolic trough collector technology and the ability to dispatch and achieve high on-peak availability for Southern California Edison (SCE), the local power utility. During the ten-year period from 1988 to 1997, the five 30-MWe SEGS plants located at Kramer Junction in California averaged 105% of rated capacity during the four-month summer on-peak period between 12 noon and 6 p.m. on weekdays (Cable, 1998). During this period, not one of the plants averaged below 100% of its 30-MWe rated capacity for even one month during the summer on-peak period. The SEGS plants are hybrid fossil/solar plants, so when insufficient sunlight is available, the turbine can be operated up to full load with fossil (natural gas) energy. On an annual basis 75% or more of the energy to the plant comes from solar energy, with natural gas providing the balance. This hybrid capability allows the SEGS plants to achieve the high demonstrated on-peak capacity factor even though only about 5%–20% of the on-peak energy during any given month comes from natural gas. The fossil backup capability allows the SEGS plants to be fully dispatchable.

From a power generation standpoint, most of the SEGS plants are performing within about 10% of original projections. The exceptions to this are (1) the first two projects, for which initial performance expectations were overly optimistic and (2) other plants that have not been maintained due to lack of available spare solar field parts. Based on the lessons learned from the SEGS plants, many of the solar field component problems experienced at the existing plants could be resolved in a next plant. In addition, better forecasts of expected future plant performance are possible. From an investor's standpoint, none of the SEGS plants have performed up to their original financial projections. This is primarily due to a drop in avoided-cost energy prices, the price paid for the power generated by the plants.

The SEGS plants represent the only successful commercial deployment of large-scale concentrating solar power technology to date. The development occurred during a period when energy prices were high and future expectations were for energy prices to continue to increase, special solar tax incentives existed, and utilities were forced to purchase power from solar QFs at very attractive rates. Since that time, fossil energy prices have reduced significantly, advances in combined cycle power plant technology have increased efficiency and reduced the cost of conventional power technologies, and a major restructuring of the electric power industry has begun resulting in much uncertainty.

Given all these changes, many believe that it is not possible to develop large-scale solar power technologies in this country. As a result, over the last several years, the parabolic trough industry has focused much of its efforts on international market opportunities. Although the power market in developing countries appears to offer a number of opportunities for parabolic trough technologies due to high growth and the availability of special financial incentives for renewables, these markets are also plagued with many difficulties for developers. In recent years there has been some renewed interest in the U.S. domestic power market as a result of an emerging green market and green pricing incentives. Unfortunately, many of these market opportunities and incentives focus on smaller, more modular technologies (such as photovoltaics or wind power), and as a result they tend to exclude or are of minimum long-term benefit to large-scale concentrating solar power technologies.

This paper looks at what is necessary for large-scale parabolic trough solar power plants to compete with state-of-the-art fossil power technology in a competitive U.S. power market. The paper starts by looking at the changes currently in progress in the power industry, and then looks at the cost of power from state-of-the-art fossil power technologies. Next, we review the cost of power from existing trough plants. Finally, we look at the opportunities for making trough plants competitive in today's power market.

U.S. POWER MARKET TRENDS

The contemporary U.S. power market is defined by two major trends. The first is the declining cost of electricity (EIA, 1997). This is driven by advances in power technology and by declining capital and operation and maintenance (O&M) costs. Major efficiency improvements and cost reductions have occurred in gas turbine and combined cycle power plant technologies. As a result there is a significant shift away from coal steam plants toward natural gas-fired gas turbine technologies for new power generation. The current fossil fuel forecasts show only modest price increases (1%/year real) for natural gas and declining coal prices over the next 20 years.

The second major trend has been the restructuring of the electric power industry. Although power sector reform is in progress all over the world, the U.S. power sector reform has primarily been the result of two factors — price differences and technology advances (EIA, 1996). The first, price differences, refers to both the variations in electricity cost among states and the difference between the cost for utilities and non-utilities to generate power. States with the highest costs tend to be leading the charge on restructuring, and industrial customers tend to be the driving force behind the effort. Their need to reduce power costs to remain competitive is driving them to look for the lowest-cost power alternatives. As a result of the Energy Policy Act of 1992 (EPACT), industrial customers are now able to obtain (or "wheel") power from wholesale electric generators, generate their own power using new highly efficient gas turbine and combined cycle technologies, or at the very least renegotiate power contracts with their local utilities. Utilities that have thrived in a regulated monopoly environment are often finding it difficult to compete with unregulated non-utility generators (NUGs). All of these factors are resulting in a breakup of the conventional power utility into three separate components: generation, distribution, and transmission. Since many utilities cannot compete with NUGs to generate low-cost power, some are even getting out of the electric generation business. This brings up the major issue facing the restructuring of the electric power industry—stranded assets. "Stranded assets" refers to the money invested by utilities in power plants in the previously regulated environment. Because utilities were required to invest in these plants, the Federal Energy Regulatory Commission (FERC) feels they should be allowed to recover a reasonable amount of this money. The primary issue is how much is reasonable. Stranded assets have been estimated to be as high as $500 billion or as low as $30 billion for the entire United States.

In any case, the restructuring is causing much uncertainty in the power industry. As a result, utilities have not been building many new power plants. In the absence of utilities building new power plants a new type of power plant, referred to as a "merchant plant," is becoming more common. Merchant plants are built as IPPs, typically without a long-term power purchase agreement. The plants are built under the assumption that they will operate as a low-cost wholesale generator that will find markets for their power once they are in operation. Typically, merchant plants are developed by companies that have access to low-cost natural gas and are located at a strategic intersection of natural gas pipelines and transmission access.

VALUE OF ELECTRICITY

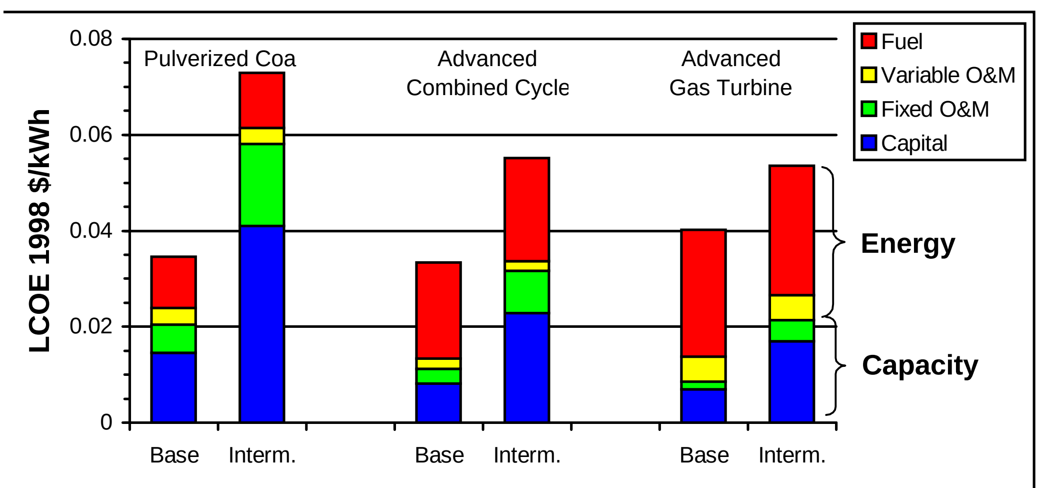
To understand the requirements for solar electric power, we must first understand the cost of power generated from competing conventional power technologies. Figure 1 shows the breakdown of the levelized cost of electricity (LCOE) for power produced from three conventional power technologies: pulverized coal, advanced combined cycle, and advanced gas turbine. Capital cost, operation and maintenance (O&M) cost, fuel cost, and heat rates are based on the Energy Information Administration's 1998 Annual Energy Outlook (EIA, 1997). The LCOEs are calculated using a 30-year cash-flow model adapted from Wiser and Kahn (1996). The key input assumptions are shown in Table 1. The LCOE is shown for baseload (85%) and intermediate load (30%) capacity factor plant operating profiles. The LCOEs are broken down into four components: capital, fixed O&M, variable O&M, and fuel. The capital component is the amortization of the capital cost of the plant spread over each kilowatt-hour produced. The fixed O&M component is the cost to have the plant staffed and available to operate. The variable O&M cost refers to the incremental cost to produce an additional kilowatt-hour of electricity. The baseload LCOEs are lower because the capital and fixed O&M costs can be amortized over more kilowatt-hours during the year.

It is important to note that the LCOEs shown in Figure 1 are very sensitive to the financial and cost assumptions used. The electric power equipment supply industry is highly competitive, and significant variations in actual cost and performance are possible depending on where a project is developed, who develops it, who pays for it, and how it is paid for. Fuel cost, fuel escalation rates, and inflation rate assumptions also become very important, especially when comparing capital-intensive and expense-intensive technologies. One important assumption that went into the development of Figure 1 is that the coal plant is assumed to be developed by a utility with access to lower cost money and who can stretch the project life to 30 years. The combined cycle and gas turbine plants are assumed to be developed as higher risk merchant type plants and as a result are financed over 20 years and with higher cost capital.

Figure 1 also shows how utilities traditionally viewed the cost of generation in terms of energy and capacity. The energy component includes the fuel and variable O&M costs. The capacity component includes the capital and fixed O&M components. Thus the capacity component represents the cost to build a plant and have it available to use. The energy component is the incremental cost of producing a kilowatt-hour of electricity. Utilities typically structure their power purchase contracts to value each of these components separately.

From Figure 1 several conclusions can be drawn. If a new plant were built, the combined cycle would be the preferred baseload technology, and the gas turbine would be the preferred intermediate load technology. However, if the plants were already built, the coal plant would be the first plant dispatched to produce an additional kilowatt-hour of electricity because it has the lowest incremental energy cost. Higher inflation or fuel costs would tend to favor coal relative to the other technologies, and tend to favor the combined-cycle over the gas turbine. Overall the advanced combined-cycle represents the best mix for a wide range of operating load factors and insurance against increasing fuel prices and inflation. The intermediate load advanced combined-cycle plant will be used as the baseline target for future parabolic trough technology to compete with. This plant generates power for approximately 5.5¢/kWh at a 30% annual capacity factor.

It is important to note that SEGS plants are fully dispatchable power plants. In areas such as the U.S. Southwest, where there is a high correlation between the power produced from solar energy and the peak system load, the plants qualify for both energy and capacity payments. The power produced from other renewable technologies that do not exhibit the same high correlation between generation and system load or are not fully dispatchable would be valued at less than 5.5¢/kWh (Table 2). Wind power, for example, would be valued at only 1.4¢/kWh – 2.3¢/kWh depending on whether it offset coal or combined cycle energy production. Based on this analysis, power from a trough plant should have a value of 3¢/kWh – 4¢/kWh greater than power from a wind plant.



igure 1. Levelized Cost of Electricity for Conventional Technologies

Table 1. Assumptions for Conventional Technologies

	Pulverized Coal	Advanced Combined Cycle	Advanced Gas Turbine
Plant Capacity - MWe	400	400	120
Design Point Heat Rate - Btu/kWh	9419	6927	9133
Capital Cost - $/kW	1079	442	300
Fixed O&M Cost - $/kWyr	23	14	6
Variable O&M Cost - mils/kWh	3.25	2	5
Fuel Type	Coal	Natural Gas	Natural Gas
Fuel Cost in 1998 - $/MMBtu	1.29	2.55	2.55
Fuel Cost Escalation Rate (Real)	-1%	1%	1%
Construction Period - Years	3	2	1
Plant Financial Life	30	20	20
Equity Stock Cost - IRR	12%	18%	18%
Cost of Debt - %	8%	9.5%	9.5%
Debt Term - Years	20	12	12
Debt Fraction	.80	.80	.80
Minimum Debt Coverage Ratio	1.3	1.3	1.3
Annual Property Tax - % of Capital Cost	1%	1%	1%
Annual Insurance Cost - % of Capital Cost	1%	1%	1%
Income Tax Rate	40%	40%	40%

Table 2. Value of Power from Renewable Technologies

Technology	Dispatchable	Correlation with System Load	Value of Power Produced	Power Technology Offset and Type of Energy Payments
Hybrid Trough	Yes	Good	5.5¢/kWh	Offsets: Combined Cycle Earns: Energy & Capacity
PV w/o storage	No	Good	2.3¢/kWh	Offsets: Combined Cycle Earns: Energy
Wind	No	Poor	1.4¢/kWh – 2.3¢/kWh	Offsets: Coal & CC Earns: Energy
Geothermal Biomass	Yes	Baseload	3.5¢/kWh	Offsets: Coal & CC Earns: Energy & Capacity

THE COST OF PARABOLIC TROUGH POWER

Figure 2 shows the reported cost of power by Luz for its 30-MWe and 80-MWe SEGS plants in 1988 dollars. To see what these plants would be expected to produce electricity for today we have made several adjustments to the Luz figures. First we corrected the values to account for the cost and performance of the plants as they were actually built. We then made adjustments to account for current tax laws and financial parameters. Finally we adjusted the cost to be in 1998 dollars. Luz reported costs of about 12¢/kWh for the 30-MWe SEGS plants and about 8¢/kWh for the 80-MWe SEGS plants in 1988 dollars (Lotker, 1991). However, if these same plants were built today, after adjustments and converting to 1998 dollars, the cost for power would be approximately 18¢/kWh for the 30-MWe plants and 16¢/kWh for the 80-MWe plants.

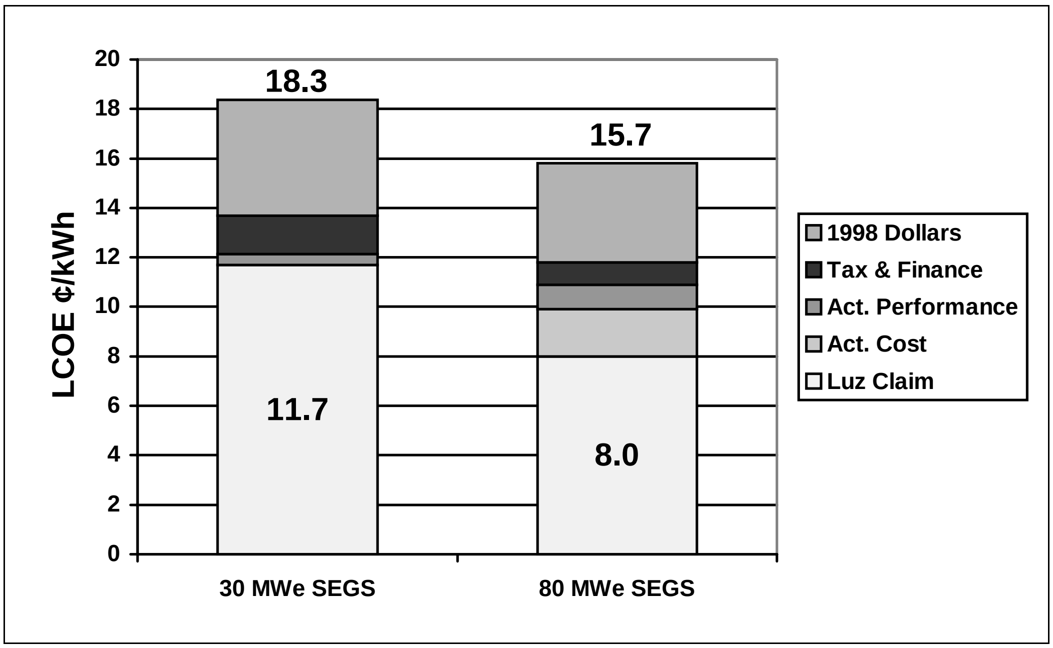


Figure 2. The Levelized Cost of Energy from the SEGS Plants

OPPORTUNITIES FOR COST REDUCTION OF PARABOLIC TROUGH POWER

The two preceding sections highlight the challenge for parabolic trough technology, reducing the cost of power for trough technology from 16¢/kWh to 5.5¢/kWh. The remainder of this paper looks at opportunities for reducing the cost of power from parabolic trough technology. In general these opportunities fall into four areas: technology improvements, cost reduction, capital cost reduction, and incentives.

Technology Improvements

Demonstrated Improvements: As a result of the KJC Operating Company O&M cost reduction study, a number of trough technology improvements have been made since the last plant was constructed (Cable, 1998). These include the replacement of the flexible hoses at the end of each collector with ball joint assemblies and improvements to the evacuated receiver tube. These upgrades have been demonstrated at the existing facilities, and should result in reduced parasitic electric consumption and decreased thermal heat losses. Based on conservative estimates, this should improve annual solar-to-electric efficiency from about 11% to 13% at new plants. In addition, the O&M study identified a number of ways to reduce the O&M cost at future plants.

Advanced Technologies: A number of advanced technology concepts have been proposed for parabolic trough power plants. These include direct steam generation in the collectors, tilted collectors, and thermal storage. At this time, it is unclear whether any of these concepts will in fact reduce the delivered cost of power.

ISCCS: The Integrated Solar Combined-Cycle System (ISCCS) is a hybrid concept that integrates a parabolic trough solar plant with a combined-cycle plant. By over-sizing the steam turbine, solar energy can be used in the combined-cycle's Rankine steam bottoming cycle. This approach reduces the cost of the conventional portion of the plant. There is concern that this concept could actually have a negative impact on the gas mode efficiency when solar energy is not available. However, in some designs this does not appear to be the case. In fact, because adding solar steam improves the utilization of waste heat from the gas turbine, the solar to electric conversion efficiency of solar steam can actually be significantly increased. The ISCCS represents an excellent near-term niche opportunity for parabolic troughs that could significantly reduce the cost of the technology. However, the remainder of this paper focuses on more conventional SEGS type trough plants.

Cost Reduction

Plant Size: One of the primary opportunities for reducing cost is to increase the size of the power plant. Although the largest plant built by Luz was only 80 MWe, this was due to federal law that limited the size. Luz believed that the optimum size was closer to 150 MWe. This size was largely a result of parasitics involved with the pumping of heat transfer fluid. By replacing flexhoses with ball joint assemblies, sizes of 200 MWe or more are probably feasible.

Solar Power Parks: Luz found that sequentially building multiple plants at the same location significantly reduced the cost of the technology. If a single project were developed such that five plants were built in succession, significant savings would result over building a single custom design. Savings would result from improved labor efficiencies and increased ability to competitively bid for components, as well as increased utilization of specialized manufacturing facilities, reduced project development and design costs, and reduced O&M costs. Preliminary estimates indicate that building five plants could easily reduce capital and O&M costs by more than 20%.

Capital Cost Reduction

Capital is the money invested to build a project. This is the complete cost including equipment, construction, and project development. There are two major types of capital investments in a project: equity and debt. The equity investment is made by the parties that will own the plant. The typical cost-of-capital for an IPP project is 18% Internal Rate of Return (IRR) after tax. The debt investment is similar to a mortgage on a house. Non-recourse debt simply means that the loan is secured by the cash flow of energy sales from the project and the debt investors cannot go after the owners if the project cannot make the loan payments.

The primary difference between solar and fossil plants is that the solar plant has a large solar field that is comparable to a 30-year fuel supply at the fossil plant. The reason this is significant is because even if the capital cost of the solar plant is the same as the fuel cost at the fossil plant, the cost of power from the solar plant will be more expensive than the cost of power from the fossil plant. This is primarily because of two factors, first any capital investment must be paid back to investors at a very high IRR, typically on the order of 18% after taxes. Second, tax policy typically treats capital investment differently than expense type investments such as fuel. By way of example, if the fuel consumption on an advanced combined-cycle plant were treated the same from a financing and taxation standpoint as a solar field, the cost of power would increase from 5.5¢/kWh to 11.1¢/kWh. The general approach suggested in this paper is to view the solar field as a fuel and to attempt to develop taxation and investment policies that help reduce the capital cost penalty on solar technologies. The primary opportunities for reducing the capital cost penalty on solar plants are to identify ways to reduce the actual cost-of-capital for the project and to eliminate local, state, and federal tax policies that penalize solar technologies.

Low-Cost Capital: Access to low-cost capital can significantly reduce the cost of solar power. One suggestion would be to develop a low-interest debt source for the solar field equipment. This could be achieved by the government providing low-cost debt a debt payment guarantee.

Risk Reduction: Risk is a general term used to describe the uncertainties that could have a negative impact on a project. Risk can result from uncertainties in cost, schedule, technology, resource availability, power sales, financial parameters, political stability, or location. When a project is being considered, investors (debt and equity) will analyze the project to evaluate the financial merit versus the risk. High financial returns are required to justify high risks. Thus, increased risk results in increased cost-of-capital. Projects using new technologies or in developing countries are usually considered high risk. Currently, trough projects require a risk premium on both equity and debt over the rates charged to conventional power technologies. To minimize technology risk it is important to utilize a technology and design very similar to the existing SEGS facilities, and to show how performance expectations can be justified from the real plant operational experience. The substantial operating experience with these plants will help minimize the premium charged for debt and equity.

Solar Property and Sales Tax Exemptions: Without special property tax exemptions, a solar power plant would be forced to pay property tax on the solar field land and equipment. Because the solar field represents a major portion of the total capital cost of the plant, property tax on this equipment represents a significant cost penalty for solar technologies. In the past, California exempted large-scale concentrating solar power technologies from paying property tax on most of the plant equipment. Even the steam power plant was exempted. Only non-solar related equipment like the back-up fossil-fired boilers were not excluded from property tax. Although this approach provides an advantage for solar over fossil power plants, it can bias local governments against the technology because they receive fewer taxes than they would from a conventional plant. The approach suggested here attempts to achieve a tax neutrality (or tax equity) between various power plant technologies. The approach is to exempt just the solar field equipment from paying property tax. The property tax payments from the conventional equipment at the plant will then be similar to the property taxes paid by other power plant technologies.

Similarly, fossil plants do not pay sales tax on their fuel, so to help achieve tax neutrality solar equipment should also be exempted from paying sales tax. Sales tax would continue to be paid on the conventional portions of the plant.

Incentives

The alternatives presented in the previous section can help reduce the inequity between capital-intensive and expense-intensive technologies; however, short of finding interest-free capital, it is unlikely to completely eliminate the cost penalty for capital-intensive technologies. This section describes a number of potential incentives than could be used to help reduce any remaining capital cost penalties for solar technologies.

Investment and Production Tax Credits: Investment tax credits (ITC), intended to encourage the development of new technologies, were a big reason for the success of the SEGS projects. State and federal investment tax credits, initially as high as 55% for the first SEGS projects, are currently down to 10%. In other technologies such as wind power, investment tax credits resulted in a significant number of tax-driven projects that either operated poorly or never operated at all. As a result, investment tax credits were replaced with electricity production–based tax credits. Given the current levels of ITCs and production tax credits (PTCs), solar technologies would be better served by switching to the same PTCs that wind technologies currently receive.

Utility Green Pricing Programs: Green pricing programs are optional programs offered by utilities to allow customers to increase their utility's reliance on renewable power (Swezey and Houston, 1998). Customers pay a premium on their electric bill to cover the incremental cost of the additional renewable energy. There are a number of green pricing approaches being used by various utilities across the country. The most prevalent is an energy-based approach in which customers can choose to purchase a block or a fixed percentage of their electric energy requirements from renewables. Typical price premiums vary from 1.5¢/kWh to 6¢/kWh.

Green Markets: A number of states have implemented retail competition as part of their utility restructuring. As a result, retail customers can now select their electric power provider in much the same way that we select a long-distance telephone service. Because of the stranded assets issue discussed above (the need to pay off the investment in existing power plants), there tends to be only minor price differences among various power providers. Thus the ability to purchase renewable energy has become one of the most attractive products in the competitive market (Wiser and Pickle, 1998). In California, customers pay green power premiums from 0.7¢/kWh to more than 3¢/kWh depending on the renewable content, the type of renewable, and whether any new renewable generation will be built. A premium of about 3¢/kWh is charged for 100% wind power with 10% new generation.

Renewable Portfolio Standards: A number of states have begun implementing renewable or solar portfolio standards as part of the restructuring of their power utilities. Portfolio standards typically require a specific percentage of renewable power to be supplied. Arizona has tentatively put in place a solar portfolio requirement of 0.5% of power sold by 1999 and increasing to 1% by 2002, with a 30¢/kWh penalty to be assessed for any shortfall.

Carbon Tax: One alternative considered to reduce CO2 emissions to the atmosphere is to place a carbon tax on fossil fuels. In a recent study performed by the U.S. Department of Energy's Energy Information Administration (EIA, 1998), a carbon tax of $348 per metric ton (1996 dollars) was necessary to achieve the U.S. carbon emission target of a 7% reduction below 1990 levels. As a point of reference, a $100 per metric ton carbon tax would increase the cost of power from a natural gas–fired combined-cycle system by approximately 1¢/kWh and by 2.5¢/kWh from coal power plants.

TROUGH CASE STUDY

What would it take for a parabolic trough power plant to compete in today's competitive power market? The following study was completed to gain a better understanding of potential opportunities for trough technology. A good market and location was identified, then an optimum plant/project configuration was selected to minimize cost. Next, an approach to achieve tax equity between solar and fossil plants was identified. Finally a number of options were identified to help offset the capital cost penalty of the "solar fuel." Using this approach, it is possible for solar to achieve economic parity with state-of-the-art fossil power technologies.

Market Opportunities for Trough Power

Given the strong correlation between power output and direct normal solar resource, concentrating solar power technologies are best suited for the southwestern United States. This region has the best direct normal solar resource in the United States. Any of the states in this region — and many areas in Mexico — represent potential market opportunities for CSP technologies.

For purposes of this analysis, California was selected as the assumed plant location. California represents a sizable market; it consumes 50% more power than Arizona, Colorado, Nevada, New Mexico, and Utah combined; and the average cost of power is 50% higher. California currently imports 20%–25% of its annual energy from outside the state. As a result of the restructuring of its electric power industry, California is experiencing a boom in merchant plant developments. Currently 2760 MWe of new merchant plant capacity is applying for permit, and applications for an additional 4000 MWe of new capacity are expected soon. The location of the existing SEGS plants in the California Mojave Desert is one of the best known solar resource regions in the world. In addition, an extensive grid of high-voltage transmission lines already pass through this region. The existence of the competitive power market provides an opportunity for solar power to be competitively marketed through the California power exchange. There is an excellent match between peak system loads and the solar power supplied from a trough plant. The power exchange has already demonstrated that the competitive market places a higher value on power generated when a solar plant operates. Since California is home to all the existing SEGS projects and has historically supported development of renewable technologies, it represents one of the best opportunities for new trough solar power plants.

Optimum Trough Plant Configuration

To minimize technology risk, SEGS type plants and Luz trough technology will be assumed. The plants are assumed to operate with solar energy whenever possible. Fossil backup would only be used during summer on-peak and mid-peak periods when the value of the power produced would be greater than the cost of producing it from natural gas. As a result the plants are assumed to operate at about a 30% annual capacity factor with only about 15% of their energy coming from the fossil backup. Plant size would be increased to 200 MWe, with multiple plants built in a solar power park. Five individual SEGS plants would be built sequentially, but they would be financed as a single project. Using these assumptions, preliminary indications are that it is possible to reduce the cost of power from a trough plant from 15.7¢/kWh to 8.3¢/kWh.

Tax Equity

The key is to get a fair taxation policy for solar technology. The concept is to treat the solar field as a fuel supply and tax it in the same manner that fossil fuel is taxed in a conventional power plant. Using this approach, sales and property taxes would not be charged on solar field equipment, and a one-year depreciation of the solar field equipment would be allowed. The non-solar portion of the solar power plant would be taxed the same as conventional power plants. We also assume that the 10% investment tax credit is replaced with the ten-year 1.5¢/kWh wind PTC. Using this approach, the cost of power drops from 8.3¢/kWh to 6.9¢/kWh.

Opportunities to Offset the Solar Fuel Capital Penalty

If the same solar tax incentives existed today that were around when the first SEGS plants were built, the cost of solar electricity would be competitive with fossil electricity. Because solar tax incentives have been significantly reduced in recent years, some additional incentives are needed for solar to compete in today's power market. A number of potential opportunities have been identified to help bridge this gap. These include:

- adding a 25% investment tax credit
- increasing the production tax credit to 3.5¢/kWh
- adding a green power incentive of 2¢/kWh
- adding a carbon tax on fossil fuels of $200/metric ton
- providing low-cost capital (6% debt for the project or 4% debt on solar equipment).

Figure 3 shows the levelized cost of electricity (LCOE) in real 1998 dollars for various trough plant configurations and for the advanced combined-cycle plant. The LCOE is broken down into its various components to show the relative capital, O&M, and fuel costs. For the solar plants, the fuel costs are broken down into fossil expense and solar capital components.

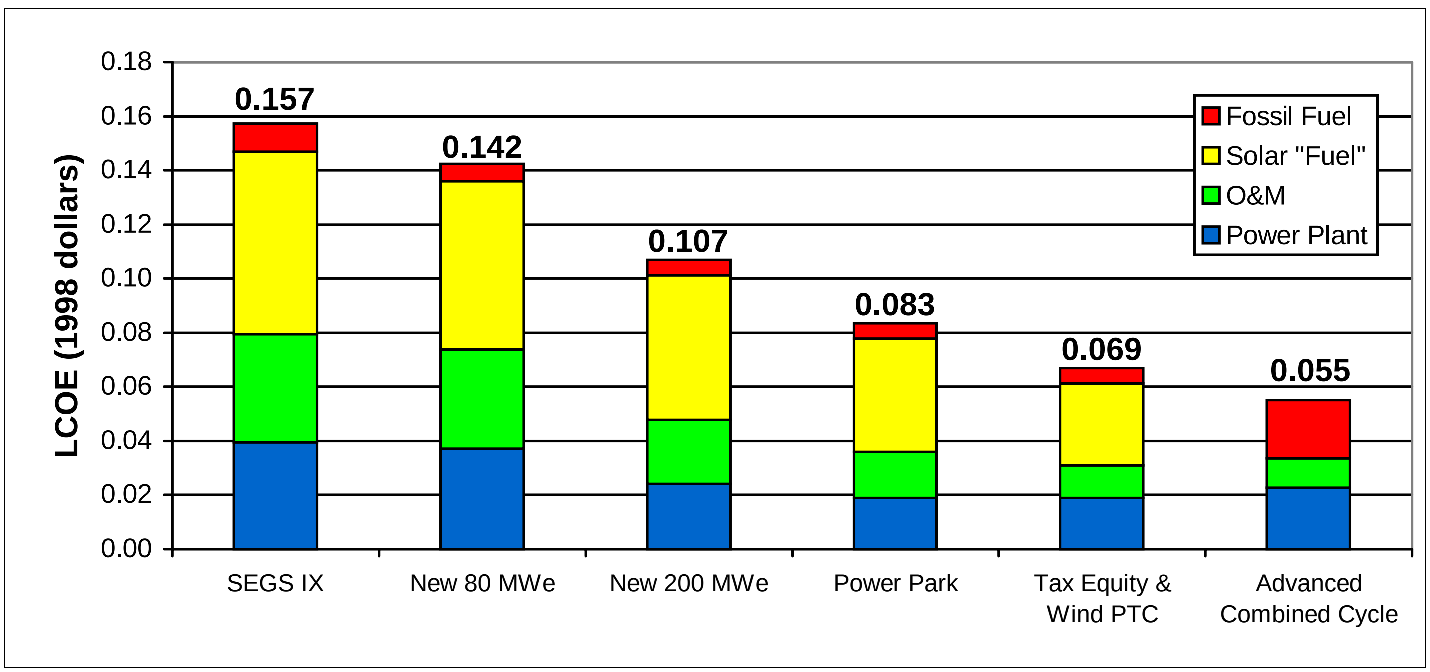


Figure 3. Trough Case Study Results

CONCLUSIONS

A significant restructuring of the U.S. electric power industry is currently in progress. This has significant implications for the development of renewable power technologies, but also provides new opportunities as the industry moves towards IPP merchant plants as the primary source of new generation.

Since trough plant electric output has been shown to be a good intermediate load match with system load, the value of the power produced can be calculated by comparing what it would cost to provide the same service with conventional fossil technologies. Based on this approach, the value of trough power is 5.5¢/kWh based on advanced combined-cycle technology. This was found to be significantly higher than the value of power from any other renewable technology.

The requirement of a solar plant to provide its 30-year fuel supply in the form of an up-front capital investment is the primary factor in making it difficult for solar technology to compete with conventional fossil fuel–based technologies. The up-front capital investment is penalized by the additional taxation burden it imposes, but more significantly by the high cost-of-capital itself. For example, if a conventional fossil power plant were required to purchase all its fuel up-front and the fuel were treated as a capital investment from a tax and financing standpoint, the cost of power would more than double. If this up-front capital investment penalty could be eliminated, trough power could compete directly with the most advanced and efficient fossil fuel technologies.

This paper developed one approach that could lead to competitive solar power in a restructured power market. The approach assumed no technology miracles, but instead relied on demonstrated trough technology currently available. The key ingredients are enabling the structured development of plants, achieving tax equity for the “solar fuel,” and finding a mechanism to help offset the remaining solar fuel cost-of-capital penalty. The structured development of plants is achieved through the development of five large 200-MWe plants in a single solar power park project. Solar fuel tax equity is achieved by splitting out the capital cost of the solar field and treating it as a fuel from a taxation standpoint. The remainder of the plant is taxed like a conventional power plant. A number of potential opportunities were presented to help offset the solar field cost-of-capital penalty, including a $200/metric ton carbon tax, a 2¢/kWh green power adder, access to low-cost debt for solar field equipment, and investment or production tax credits.

Given that appropriate equalizers can be put in place, parabolic trough technology is positioned for significant project development opportunities.

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