21

Economic Analysis and Environmental Aspects of Photovoltaic Systems

Richard A. Whisnant[1], Stephen A. Johnston[2] and James H. Hutchby[3]

[1]*Parameters, Inc., Cary, North Carolina,* [2]*Research Triangle Institute, Research Triangle Park, North Carolina* [3]*Semiconductor Research Corporation, Research Triangle Park, North Carolina*

Photovoltaic (PV) systems provide electric energy, and the range of uses for electricity and the situations in which it is employed are enormous. Moreover, there are numerous other well-developed and widely used technologies for supplying electricity. Conventional fossil-fuel and hydroelectric generation are presently far more widely deployed than PV. The question arises, then, of how PV systems can penetrate the world's electric supply in competition with these alternatives, or, more narrowly, how a PV system can compete with other electricity sources for a specified application. At this point in time, there are many PV systems that do compete successfully in applications for which they are particularly suited. In other applications, PV systems have been deployed with the support of financial subsidies from private or public sources in order to either satisfy defined energy needs or to demonstrate the potential for PV systems. In all cases, it is useful to understand the economic viability, whether present or future, of any PV system in a given application. It is the purpose of this chapter to define and illustrate methods of defining the economics of PV systems as measured by conventional financial criteria and the cost of delivered energy. The cost of delivered energy is a fundamental characteristic of PV systems, and it can be influenced by the design and performance of the system, as well as by the sources and costs of capital to fund the system. The choice to deploy PV in a given situation is also influenced by other issues, including competition from the established electric supply, financial risk, and environmental, political, and humanitarian concerns.

Handbook of Photovoltaic Science and Engineering. Edited by A. Luque and S. Hegedus
 ISBN: 0-471-49196-9

21.1 BACKGROUND

A rational decision to develop, supply, or utilize PV systems calls for consideration of many factors in an organized manner so as to address the broad issue of whether photovoltaics is a good choice for the person or institution making the decision. Electric energy today can be provided from many sources that are both nonrenewable (including coal, oil, natural gas, nuclear) and renewable (such as wind, biomass, hydro, PV). PV systems compete, in the broadest sense of the word, against the other sources. The competition encompasses financial, reliability, environmental, and performance considerations, and the weight given to these factors will depend on the decision maker's priorities. The values of the parameters in the decision process are defined by well-developed and widely available energy-supply technologies. Economic analysis in the developed world usually focuses on which supply technology best meets the well-defined economic criteria for a given application or class of applications. The preponderance of the use of electric energy in the developed world is available from an electric supply grid, and the competitiveness of PV systems is often evaluated in that context. There are some off-grid demands that can be supplied by PV systems, and for which they are technically well qualified. In the United States, such applications include remote vacation homes or public buildings, navigation buoy signals, communications repeaters, outdoor signage, and irrigation pumping.

In less-developed areas of the world, which for the present discussion mean areas without electric-power grids, the context of the decision process is different. PV systems in such areas are often termed *remote* or *village* systems. They may be deployed in individual homes, small businesses, or may serve a community with local distribution of energy. The competition faced by PV systems in these settings is usually from diesel oil–powered generators (nonrenewable source) or from small renewable sources (such as wind, hydro, biomass). The factors in the decision to deploy PV systems may include factors common to developed regions, though there may be fewer energy alternatives, and generally the individual system capacities are much smaller than in developed regions. However, in less-developed regions of the world, certain other factors may assume greater importance. The viability of the systems is a serious issue if the infrastructure for their installation and maintenance is lacking. Conversely, the provision of that infrastructure to provide installation and maintenance may be a more significant concern than in developed regions. It may also vary among energy technologies, and to that extent it is a competitive factor. For example, diesel generators must be supplied with fuel on a periodic basis, and they have moving parts that must periodically be repaired or replaced. PV systems do not require fuel supply and have no moving parts to repair. However, this does not mean that they would never need repair or replacement.

The financial considerations in a decision to deploy PV can be quite different in developed regions than in the undeveloped regions. In a developed country, the economic units (e.g. individuals, families, businesses, government operations) have a cash flow and well-defined energy needs. The question that they must answer periodically is what source of energy will they choose from among competing alternatives that are highly developed and more or less readily available. The question can be addressed in a quantitative fashion, at varying levels of sophistication, and the resources are available to implement the choice. In undeveloped regions, the situation is more likely that the economic units are individuals or very small businesses with little or no cash flow. The question for these regions is whether any electric energy is at all affordable and where do the resources to pay for it come from. The purely financial comparison of electricity sources by private entities often becomes subservient to public economic-development initiatives, and national and international politics may play a strong role. The choice of electric energy sources for the classes of applications must still be made, and the cost of energy delivered, in the sense employed for developed regions may still be computed, but generally not by individuals or small economic units, because they will not pay for them.

21.2 ECONOMIC ANALYSIS

Once the technical requirements of a PV application have been stated and a PV system design completed, the economic analysis can be carried out. The economic assessment includes both costs and benefits of the system. The methodology for this assessment constitutes a major portion of this chapter.

21.2.1 Key Concepts

The purchase of a PV system represents an expenditure of capital resources at a given time with the expectation of benefits in the form of electric energy delivered over some future period, which is generally the life of the PV system. Other benefits, such as reductions in greenhouse gases, might be quantified. For large systems, the construction expenditures may occur over more than one year. The future benefits, primarily the value of the electricity generated, may be realized over a 10- to 30-year period. Thus, the basic issue is how to measure the value of future benefits from a present expenditure. Further, the issue is how to compare that value for a PV system with a consistently defined value for an alternative system such as a diesel-electric system, a fuel cell, or electricity from the grid. Salvage value at the end of the system life is also a future benefit. In many cases, there will not only be future benefits but future costs as well. The cost of maintenance and the replacement of failed modules are primary examples. In addition, qualitative benefits, such as energy independence or reduction in the risk of future escalation of energy costs, may enter the decision process, although they are not dealt with here.

We generally recognize intuitively that the value of a cost or benefit in the future is not equal to the same cost or benefit today. If we were to receive \$100, we would rather get it today than five years from now. Why? Perhaps because we could buy something today with the money and enjoy its use for the next five years, rather than wait to enjoy it. More practically, we could put the \$100 in a savings account and it would be worth perhaps \$125 in 5 years; so the value of money possessed now as opposed to later can be measured in this simple way. All of this goes to say that there is a "time value of money," and defining that time value pervades the whole process of economic analysis for PV systems. These expenditures and benefits, as measured in monetary terms, are usually called *cash flows*.

As suggested above, the purchase and operation of a PV system involves a stream of cash flows over a period of years, and economic assessment requires some consistent measure of these cash flows to be made. It may in some instances require the comparison of the value associated with that stream with the value of a different stream for a competing system. For a PV system, such a stream might look like what is shown in Figure 21.1. Outflows, such as the purchase cost and maintenance costs, are shown as negative, while

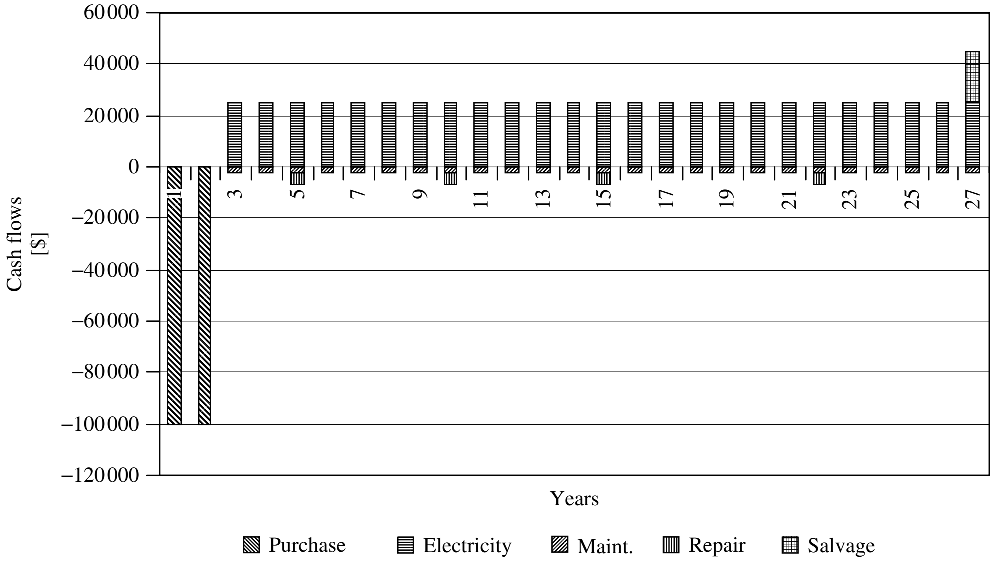

Figure 21.1 Example of PV system cash flows

inflows, such as the value of electricity produced and the salvage value, are shown as positive. In Figure 21.1, it is assumed that the system construction covers 2 years and outlays are \$100 000 in each year; the value of electricity generated is \$25 000 per year for the next 25 years; annual maintenance costs are \$2000; there are replacement costs of \$5000 in Years 5, 10, 15, and 20; and the salvage value is \$20 000 at the end of Year 27. For a PV system, the value of the generated electricity is usually determined by the avoided cost of the electricity that would otherwise need to be purchased. Note that the annual electricity production in kilowatt hour from the PV system is implicitly included in this example through the determination of the electricity cost stream. If the PV system is remotely situated, the PV electricity might alternatively be valued by its contribution to its end-use activity, though this valuation may be easier said than done.

To put a single value on these cost and benefit streams occurring over time, the usual approach is to refer all costs and benefits to a selected point in time, usually the present time, sum the values for the given streams, and compare the sums. These sums are called the *present value* or *present worth* of the systems. To compare two or more systems with one another, the present worth of each is computed to provide an economic comparison.

A sum received or spent at the present time has a present worth, P. A sum spent or received at a future time n years hence has a future worth, F. If P is invested at an interest rate of i percent per year, then its future worth at the end of the first year is

$$F = P + Pi = P(1 + i)$$

The future worth at the end of the second year is

$$F = [P(1 + i)](1 + i) = P(1 + i)^2$$

and the future worth after n years is

$$F = P(1 + i)^n \tag{21.1}$$

Conversely, the present worth of a future sum is given by

$$P = F(1 + i)^{-n} \tag{21.2}$$

Equation (21.2) shows that the present worth of a sum received n years in the future is reduced by the factor $(1 + \mathrm{i})^n$.

When equations (21.1 and 21.2) refer to the money deposited at interest, the factor i is the interest rate offered by the bank, but when an investment in an energy system is being considered, the factor i is referred to as a *discount rate*. The discount rate is the value that the system owner puts on the capital invested in the system, and is often called the opportunity cost of the investor; that is, the rate of return foregone on the next most attractive investment.

In Figure 21.1, the annual delivered energy values of \$25 000 constitute a uniform stream of cash flows. The sum of the future worth of each of these annual amounts, a, is, from equation (21.1)

$$F = a[1 + (1 + i) + (1 + i)^2 + \cdots + (1 + i)^{n-1}]$$

This relationship can be shown to be equivalent to [1]

$$F = a[(1 + i)^n - 1] \div i \tag{21.3}$$

By combining equations (21.2 and 21.3), the present worth of a uniform series of amounts a can be stated as

$$P = a\frac{[(1 + i)^n - 1]}{[i(1 + i)^n]} \tag{21.4}$$

Consider the application of equations (21.2–21.4) to the simplified example of cash flows in Figure 21.1. The value of the PV system as measured by present worth at the beginning of Year 3, the time the system begins to produce electricity, is P_s.

$$P_s = P_{\text{investment}} + P_{\text{electricity}} + P_{\text{maintenance}} + P_{\text{replacement}} + P_{\text{salvage}} \tag{21.5}$$

Equation (21.5) implies that each of the components of P_s is referred to the same point in time, beginning of Year 3, and can therefore be summed. Table 21.1 summarizes the computation of P_s. Assume that the two \$100 000 investments are made as of the beginning of Years 1 and 2, and that all other amounts are as of year-end. Assume a discount rate, i, of 8%. Note that in Table 21.1 expenditures, or outflows, are shown as negative numbers and benefits, or inflows, are shown as positive. The appropriate equation for each category is indicated and the value of the exponent, n, required to reference the present-worth values to the beginning of Year 3 is also given. Note that cash flows that occur later in the system life contribute less to the system present worth, relative to their current values, than those that occur earlier.

Table 21.1 Present worth of PV system cash flows shown in Figure 21.1 (discount rate = 8%)

Cash flow		Present worth		
Category	Amount [$]	n	Equation	P [$]
Year 1 investment	−100 000	2	(21.1)	$P_{\text{investment}} = -116\,640$
Year 2 investment	−100 000	1	(21.1)	$P_{\text{investment}} = -108\,000$
Annual electricity, Years 3–27	25 000	25	(21.4)	$P_{\text{electricity}} = 266\,869$
Replacement, Year 5	−5 000	5	(21.2)	$P_{\text{replacement}} = -3403$
Replacement, Year 10	−5 000	10	(21.2)	$P_{\text{replacement}} = -2316$
Replacement, Year 15	−5 000	15	(21.2)	$P_{\text{replacement}} = -1576$
Replacement, Year 20	−5 000	20	(21.2)	$P_{\text{replacement}} = -1073$
Annual maintenance, Years 3–27	−2 000	25	(21.4)	$P_{\text{maintenance}} = -21\,350$
Salvage value, Year 27	20 000	25	(21.2)	$P_{\text{salvage}} = 2920$
Total			(21.5)	$P_{\text{s}} = 15\,431$

This PV system present worth is positive, and thus the system can be said to have a net benefit of $15 431 measured at the beginning of Year 3. Whether this is an acceptable economic choice would depend on the economic criteria of the system purchaser. This subject will be discussed again later.

There are instances when the annual amounts a in equation (21.4) are not uniform (constant) over all periods, but escalate at a constant rate, e. That is, if c is defined as the amount for the first year, the amount for the second year is $c(1+e)$, and the amount for the third year is $c(1+e)^2$. An obvious instance of where such a series of cash flows might arise would be in accounting for the effect of inflation on the value of avoided electricity. In this instance, the present worth of the series of cash flows can be expressed [1], when $e > i$, as

$$P = \frac{c}{1+i}\left\{\frac{(1+x)^n - 1}{x}\right\} \tag{21.6}$$

where x is defined by

$$\frac{1+e}{1+i} = 1 + x \tag{21.6a}$$

If the escalation rate is less than the discount rate, $e < i$, then

$$P = \frac{c}{1+e}\left\{\frac{(1+x)^n - 1}{x(1+x)^n}\right\} \tag{21.7}$$

where x is defined by

$$\frac{1+e}{1+i} = \frac{1}{1+x} \tag{21.7a}$$

If the escalation rate equals the discount rate, $e = i$, then

$$P = cn/(1+e) = cn/(1+i) \tag{21.8}$$

When a financial evaluation of a PV system project is defined, such as the one in Figure 21.1, it is important to be clear about how inflation will be taken into account.

When Figure 21.1 was defined, inflation was not mentioned, and the cash flows shown for the electricity value were constant over a number of years. Such a problem statement is consistent with a "real dollar" or "constant worth dollar" or just "constant dollar" approach. In this view, all monetary values are stated in terms of their purchasing power at the point in time at which the present worth of the system will be calculated. The computation of the present worth is a little simpler for a constant-dollar formulation, but that approach can mask some real-world inflationary effects. For example, the inflation of avoided electricity prices may be different from the inflation of labor required for maintenance or components used in replacing failed modules. When explicitly taking inflation into account, the monetary amounts in the cash flows are stated in terms of the actual dollar transactions at the time at which they occur. These amounts are called *actual dollars, then-current dollars*, or just *current dollars*.

Since the calculation of present worth measures is usually carried out for the purpose of comparing system alternatives, it can be argued that useful comparisons can be made in either constant-dollar or current-dollar terms. Where the differences in system measures turn out to be relatively large, that argument is likely to be valid, because the difference in the systems is obvious. However, there may be instances in which the outcome could be skewed if inflation is not properly calculated.

Thus far, the discussion has assumed present worth calculations either on a constant-dollar basis or on a current-dollar basis with inflation at a constant rate. It is also possible that a constant inflation rate does not adequately represent the future. If the inflation rate (or the discount rate) varies over the period of the analysis, then, practically speaking, one is forced to calculate separately the present worth of each future cash transaction and add the terms to get a system present worth.

It needs to be emphasized here that the computation of a present-worth measure for some energy alternatives requires the projection of cash flows (transactions) up to 30 years into the future, and thus the result depends not just on the proper application of computational methods, but on the assumptions and information that go into this projection. The cash flows to be projected include energy prices, materials costs, labor costs, cost of capital, and related factors. This requirement often leads to the parameterization of critical factors and economic analysis under a range of scenarios rather than a single set of assumptions. Fortunately, the effect of the discount rate is to reduce the impact of projections far into the future relative to those in the near term.

Now, let us consider a more general statement of cash flow that supports the definition of additional economic measures of PV systems. The statement assumes that a PV system will be purchased, installed, and operated over a period of years by a profit-making organization. For a given year, n, the net cash flow based on returns to equity capital is [2]

$$X_n = (R_n - C_n - I_n) - (R_n - C_n - I_n - D_n)T - K_n + S_n + B_n - P_n \pm W_n \qquad (21.9)$$

The terms of equation (21.9) are as follows.

$R_n =$ gross revenue due to the system in the year n; typically the value of the electricity generated.

C_n = cost associated with the operation and maintenance of the system in year n; including labor, materials, and replacement parts.
I_n = debt interest paid in year n on funds borrowed (B defined below) to fund the system.
D_n = tax depreciation in year n for the system, assuming that the taxation applicable to the owner allows deduction of depreciation for tax purposes, calculated as allowed by the tax law.
T = incremental (marginal) tax rate for the owner; the second term in parentheses in equation (21.9) represents the taxes on income paid by the owner.
K_n = capital expenditure in year n; the total amount spent on capital assets.
S_n = salvage value received in year n.
B_n = amount of money borrowed in year n from external sources and used to fund capital expenditures.
P_n = payment of principal on debt capital (B) in year n.
W_n = net increase in working capital in year n; has a negative sign if an increase in working capital is required; working capital represents the funds employed for such items as payroll, inventories, and accounts receivable.

The definition of net cash flow on an equity capital basis is used here because profit-making organizations tend to judge their financial performance based on returns on equity capital.

The annual net cash flow in equation (21.9) for each year in a PV project life must be used with equation (21.10) to calculate a system present worth that is comparable to the result P_s shown in Table 21.1.

$$NPW = \sum_{n=0}^{L} \frac{X_n}{(1+m)^n} \tag{21.10}$$

where

X_n = annual net cash flow from equation (21.9).
L = system life or the life of the project for evaluation purposes.
m = the minimum acceptable rate of return on equity capital.

The quantity m is equivalent mathematically to the discount rate i used earlier (e.g. equations (21.1–21.3), but m has the additional stipulation that it represents a requirement of the system owner for returns on equity. It may or may not be the opportunity cost. It may represent a hurdle rate set to determine what the owner requires in order to take the financial risk represented by the project.

In Table 21.1, the present worth of each component (investment, annual electricity, replacement, maintenance, and salvage) was calculated over the project life, and the component present worth figures were added to get a system present worth. Equation (21.9) adds the figures for all components (investment, annual electricity, replacement, maintenance, and salvage) in any given year to get the annual net cash flow for that year. Then, the annual net cash flows are discounted in equation (21.10) to get the system present worth, which is called net present worth (NPW). Thus, the order of computation is different in Table 21.1 from that of equations (21.9 and 21.10), but the result is the same. Equations (21.9 and 21.10) are just a more general expression of the computational process than Table 21.1.

Note also that if the PV system owner is selling electricity and thus has a revenue (income) stream, that revenue is taxable as per equation (21.9). However, if the PV system owner is not selling electricity, then the electricity has a value to the owner and the term R in equation (21.9) can be used in the calculation of the system worth, but the taxation term is zero because $T = 0$. (The case of $T = 0$ is implicit in Table 21.1.)

Several other measures of system worth can be defined using the annual net cash flow defined by equation (21.9).

$$0 = \sum_{n=0}^{L} \frac{X_n}{(1 + IRR)^n} \tag{21.11}$$

where

IRR = internal rate of return.

Equation (21.11) is solved iteratively for the value of internal rate of return (IRR) that satisfies the equation. To determine if the investment in the PV system is acceptable, the IRR must be compared to a hurdle rate set by the owner. This rate may or may not be the owner's opportunity cost.

A less-sophisticated economic measure is the simple payback period defined by

$$0 = \sum_{n=0}^{\mathrm{PB}} X_n \tag{21.12}$$

where

PB = payback period in years.

The payback period is the number of years required for the inflows to equal the outflows. It is the time required to recover the initial investment in the system. This measure is referred to as *simple* because it does not consider the time value of money (there is no discounting). It also does not consider cash flows beyond the time when the investment is recovered. Simple payback is probably more useful, for example, to the homeowner who does not have the same tax and profit considerations as the business owner.

A measure of the intermediate complexity and usefulness is the discounted payback period, defined as

$$0 = \sum_{n=0}^{\mathrm{DPB}} \frac{X_n}{(1 + m)^n} \tag{21.13}$$

where

DPB = discounted payback period.

The discounted payback period (DPB) does consider the time value of money, but does not consider the cash flow after the recovery of the initial investment.

Finally, there is another method of valuing PV systems that uses some of the same mathematical techniques as the above measures, but expresses the result differently; namely, the levelized energy cost (LEC) or levelized bus bar energy cost (LBEC). This approach is particularly appropriate to energy providers such as electric utilities. This method provides a unit cost of electricity in \$/kWh that is constant over time (i.e. levelized) and expressed in monetary units at the beginning of a commercial operation. The LEC method is useful to utilities, who sell electricity on a \$/kWh basis, since it is easy to compare the computed LEC to the costs of electricity from other conventional or renewable sources. This method can also be adapted for nonutility system owners.

The LEC method is based on the same discounted cash-flow concepts illustrated by Table 21.1 and equations (21.1–21.8). These latter results represent the total discounted worth of a PV system over its economic life stated in dollars, and these dollars implicitly incorporate the annual PV energy produced. The LEC method, in effect, takes a present worth of the cost (but not revenue) streams as in equation (21.9) and computes a stream of constant annual values having the same present worth. This annual value is divided by the rated annual energy production of the system to get an annualized cost of electricity.

$$LEC = \frac{(NPW_C)(CRF)}{E} \tag{21.14}$$

where CRF is called the capital recovery factor, defined as

$$CRF = \frac{m(1+m)^n}{(1+m)^n - 1} = \frac{a}{P} \tag{21.15}$$

The capital recovery factor (CRF) is the inverse of the present worth of a uniform series defined in equation (21.4). NPW_C is computed from equation (21.10), which, in turn, is based on equation (21.8) with revenues, R, set to zero. The numerator of equation (21.14) is the annualized value of the costs associated with the system construction and operation, that is, it defines a uniform annual series of costs that have the same present value as NPW_C. The term E is the annual energy in kilowatt hour generated by the system.

21.2.2 General Methodology

A general methodology for the economic assessment of PV systems is illustrated in Figure 21.2. The assessment begins in Step 1, system design, which must be done prior to an economic analysis. For an assessment addressing multiple systems and/or applications, the methodology of Figure 21.2 must be carried out for each system of interest and the results summed to determine the economic potential.

Steps 2, 3, 4: system cost. In determining system cost, completeness and accuracy in individual component costs lead to a good estimate of system cost. Figure 21.2 suggests two paths to estimate system cost. If the system design is based on the currently available technology, then defining a complete bill of materials and then obtaining quotations from the vendors is the path to be followed. If the cell/module technology is to be projected into the future, or if a current technology is not in volume production so that its costs are not available, then the price can be predicted from the modeling of the manufacturing process.

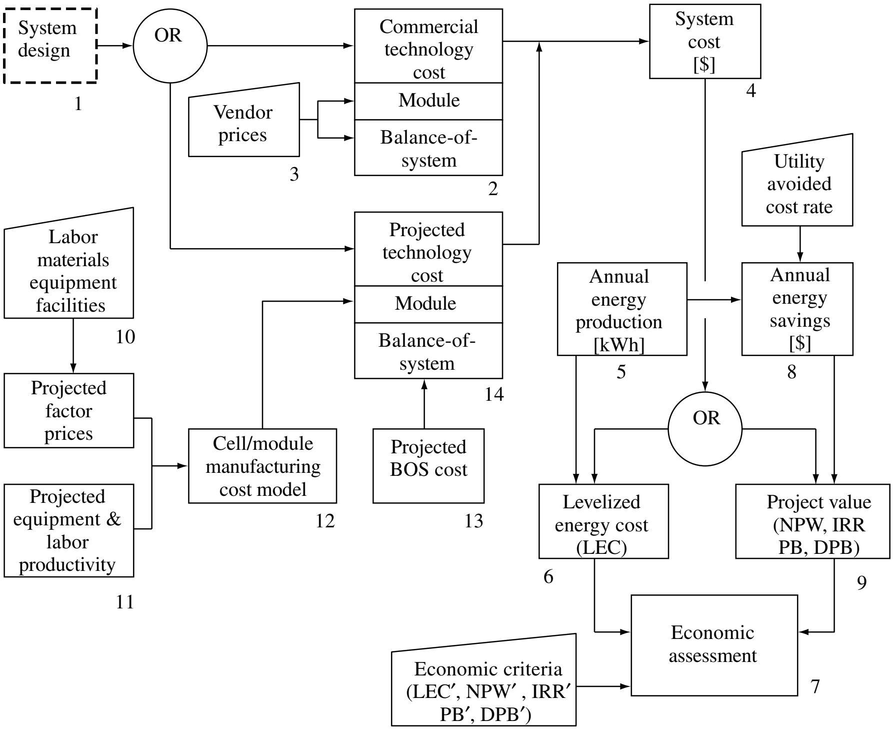

Figure 21.2 Economic assessment

Such a modeling procedure is discussed later in this section. For either path, the system components and materials, aside from the cells and modules, are in general commercially available and the prices can be obtained from manufacturers and distributors. A limited number of cells and modules are also commercially available. System components are particular to the design, and the following list suggests the major components whose costs are required. Detail part specifications and costs are needed in many cases for accurate costing.

- PV cells
- PV modules
- Module support structure
- Tracking structure/drives/controls
- Heliostats
- Foundations and structures
- Cooling system
- Interconnection wiring and terminations
- Power-conditioning unit
- Transfer switching and metering
- Substation equipment
- Land

- Site improvements (grading, roads, fencing, buildings)
- Installation labor and management
- Financing cost during construction
- Shipping
- Taxes
- Licenses, permits.

For large systems whose installation may extend over months or years, a schedule of installation and expenditures will also be needed to properly compute economic measures as defined previously.

Steps 10, 11, 12, 13, 14, 4: system cost (manufacturing-cost modeling). Figure 21.2 shows two paths to determine the system cost. The path utilizing commercial technology has been addressed in the figure. When a PV cell/module technology that is not commercially available is to be considered, predictions of the cell and/or module cost are required. One approach to predicting the cell/module costs is shown in Figure 21.2 (Step 12) as a cell/module-manufacturing cost model. Such a model was developed at the Research Triangle Institute under the sponsorship of the Electric Power Research Institute (EPRI), and was used over a period of years in studies of the cell and module costs [3]. This modeling approach, which eventually came to be called Strategic Analysis of Manufacturing Product and Price (STAMPP), is briefly described here to illustrate how cell/module costs can be predicted.

The objective of STAMPP is to model the operations of a cell- or module-manufacturing firm in such a way that the annual required revenue of the firm is calculated for a specified annual production volume. The required revenue divided by the production volume gives a required unit price for the cell or module. The term *required price* is used because all direct and indirect costs and after-tax profit are included in the revenue. The required price is thus the minimum price for which the product could be sold while returning the specified margin of profit. However, the market would always determine the actual selling price. A further objective of the model is to facilitate the parametric analysis of a wide range of cost factors so that the cost drivers can be identified and their effect on the required price of a cell or module design can be explored for a specified manufacturing process.

The firm is described in the model by a fixed organization whose top management levels are filled by a fixed number of people. The lower levels of the organization, including supervisors, production, and support staff are filled by a number of employees, which is scaled to the manufacturing requirements. Hours of operation, meteorological data for heating/cooling loads, and other firm-level financial and operating data are included among the input.

The physical operations of manufacturing are modeled in STAMPP using the concept of a "workstation". A workstation is defined as a collection of one or more identical machines, each performing the same operations in parallel. The user specifies the direction of workflow among the workstations.

The user defines the operations performed at a workstation on a per-machine basis. The model calculates the number of machines for each workstation based on a specified annual volume of the final product and the workstation characteristics. The workstation is characterized by the nominal operating parameters of one of its machines, which are defined as long-term average values. The quantity of work done at each workstation is determined by the model from a process balance using as inputs the total annual product volume from the last workstation, and individual machine parameters including

- form conversion factor (input/output units),
- yield (number of good units out per unit time/ideal production rate),
- machine ideal production rate,
- machine availability.

The quantity of required materials is determined from the workstation-level, per-product-unit consumption factors and the workstation product quantity, and the quantity of labor of specified types is determined from per-machine labor requirements. Total materials, labor, utilities, and floor-space requirements are summed for the firm, and their costs are calculated using these quantities and unit costs input to a cost catalog. Unit costs of process equipment and facilities are used to compute the capital investment for the plant.

Using the calculated production costs, the model produces a corporate income statement and balance sheet. These reports are based on accepted accounting procedures. The income statement provides the revenue to calculate the product cost. The data in both reports can be compared to the data for typical real businesses to assess the appropriateness of the modeling from a business point of view. On the manufacturing side, reports are provided that summarize the equipment, labor, materials, floor space, and utilities required in terms of both quantity and cost. Also reported are personnel and associated costs for administrative functions. The result is a complete picture of all aspects of the cost structure underlying the required product price. In the subsequent section, outputs from the model are shown to illustrate an economic assessment of a PV power plant.

Step 5: annual energy production. Within the assessment framework of Figure 21.2, the annual energy production for the system will be calculated from local solar data and the performance parameters of the system (as described elsewhere). For a private user, the energy considered here is the *useful* energy; that is, the energy actually consumed by the load plus any energy sold back to a utility. For a utility, all of the energy produced is useful.

Step 6: levelized energy cost (LEC). LEC is defined in equation (21.14) as a constant annual cost ($/kWh) over a specified period of years whose present worth is the same as that of the cost stream associated with its production. The cost stream was defined in equation (21.9). LEC incorporates the cost of capital and the annual energy production. LEC is typically computed by utilities, but could also be used by private PV system owners.

Step 7: economic assessment. The final step in this assessment methodology is to decide if the value of the economic measure computed is an acceptable value when compared to an economic criterion. Where LEC is the economic measure, it is compared with the cost of electricity (LEC′) from other sources calculated in the same manner. For a private user, the comparison value might be that of electricity from, for example, a diesel-electric generator or a fuel cell. For a utility, this comparison may entail the consideration of the system-capacity expansion for a given load growth in order to determine the alternative cost of electricity, or a simpler approach might be just the utility's cost of peaking power. The problem with the simpler approach is that it may not adequately consider issues such as reserve capacity.

Step 8: annual energy value. In order to calculate the project value measures in Step 9, the value of the annual energy production is needed. For grid-connected, customer-side systems, the value is the cost avoided by not purchasing the annual energy produced (Step 5). The value is calculated from the electric utility rate and the energy production. Where the rate is multitiered or has seasonal components, the energy production as a function of time would need to be taken into account in order to value the energy properly.

Step 9: project value. Several financial measures for PV systems have been defined in equations (21.10 to 21.13): NPW($), IRR(%), PB(years), and DPB(years). Each one depends on the net equity cash flow, X_n, defined by equation (21.9), which includes a revenue term, R, which is the value of the electricity purchase avoided by the use of the PV system. The annual electric energy produced by the PV system is implicitly included in R.

When the computed economic measure is NPW, IRR, PB or DPB, it is compared to the threshold (NPW′, IRR′, PB′, DPB′) values that the owner considers appropriate. If the owner is a commercial firm, the NPW or IRR measures would typically be used. If the decision is between two competing energy sources, say, PV and a fuel cell, the one with the higher NPW or IRR would be preferable. It should be noted that since the fuel-cell system is dispatchable (i.e. provides energy at any time on demand), the PV system is not comparable unless it includes storage. The two systems must be designed to meet the same load profile in order to be compared by a single measure such as NPW or IRR. If the decision for the commercial user is just whether to buy a PV system for a stated purpose, the issue then is whether the NPW or IRR is greater than some threshold value. In this instance, the PV system competes for capital with other capital needs of the firm, and the threshold may be set by considering the NPW or IRR associated with alternative capital expenditures. The firm may even look at the decision in both ways: is the PV system the best choice from among several systems *and* is it a better use of capital than nonenergy expenditures.

The payback (PB) and discounted payback (DPB) measures are more typically appropriate to homeowners or others without tax considerations in the purchase decision, although nothing prevents others from considering these criteria. The payback for the PV system can be compared to the life of the system as a decision criterion. If the payback is shorter than the life, then in a simple view the energy is free after the payback period. Another use of the payback measures is to compare two or more systems by calculating their payback; the one with the shortest payback is preferred.

21.2.3 Case Studies

To illustrate some of the methodologies for the economic analysis of PV systems, brief summaries of three studies in which the authors participated are presented here. Each study considered PV technology operated in a large-scale (25–50 MW) electric-utility setting. The first study [3] compared the required module price in $\$/W_p$ of several Si-cell technologies. The second study [4] covered silicon and copper indium diselenide (CIS) technology, and the third [5] compared the 500X concentrator systems with Si technology to GaAs technology in plants of the same annual energy capacity. All three studies modeled the cell- and module-manufacturing processes using the STAMPP model, and included both flat-plate and 500X concentrator collectors.

Financial studies of complex systems require extensive data input, and can produce volumes of data output. Restriction of space in this chapter limits the details that can be provided to only a small fraction of what was there in the original studies. The numerical values of inputs and outputs are based on the time at which the studies were performed, so the objective is to illustrate methodology and relative technology comparisons, not to give current quantitative cost results.

21.2.3.1 Module price for silicon technology

From the beginning of the photovoltaic commercialization efforts in the 1970s, crystalline-silicon-cell technology has been dominant. The availability of refined silicon wafers resulting from semiconductor development, the availability of mature processing equipment developed by that industry, and the simplicity of the Si-cell fabrication technology relative to thin-film Si or compound semiconductors such as gallium arsenide or copper indium diselenide were, and still are, major factors that influence the role of silicon in photovoltaics. The first cost analysis conducted by the authors [3], which was also the genesis of the STAMPP program defined earlier, compared silicon-module prices fabricated by several different methods. (In [3], the STAMPP model was called IMCAP, but the model is essentially the same.) While the results discussed here were determined in 1986, there still are some relevant and useful lessons to be learned from the comparison of different cell- and module-fabrication methods, and the focus here is on these rather than on current absolute cost of cells and modules.

Five different cell technologies and modules fabricated from them were examined in this study:

- Flat-plate modules using silicon cells from single-crystal Czochralski wafers.
- Flat-plate modules using silicon cells fabricated on silicon dendritic web substrate.
- Flat-plate modules using single-junction amorphous-silicon cells (a-Si:H) grown on glass.
- Flat-plate modules using tandem-junction amorphous-silicon cells (a-Si:H/a-SiGe:H) grown on glass.
- 500X Fresnel lens concentrator module using high-performance cells from float-zone single-crystal silicon wafers.

The concentrator module incorporated cells under separate development by the study sponsor and the cell fabrication was not modeled with STAMPP. The cells were treated as a purchased item. All of the manufacturing processes were defined to produce annually modules with a total rating of 25 MW.

The module prices computed for this study were intended to give a comparison of significantly different cell technologies and to provide a perspective on how low the prices might fall in the future. The cost of materials and other items for a base case

Table 21.2 Key technical and financial parameters [3]

Parameter	Process case			
	Technology	Base	Pessimistic	Optimistic
Module efficiency (%)	Czochralski	15.0	12.0	17.0
	Dendritic web	15.0	12.0	17.0
	Concentrator	19.42	17.09	21.75
	a-Si:H	10.0	6.0	12.0
Silicon price ($)	Czochralski	40/kg	75/kg	25/kg
	Dendritic web	40/kg	75/kg	25/kg
	Concentrator	2.00/cell	4.00/cell	1.00/cell
	a-Si:H (silane)	618/kg	2000/kg	150/kg
Glass ($/m^2)	All	10.76	13.46	8.07
Wafer/Kerf Thk. (mil)	Czochralski	12/10	14/12	10/6
Web pull rate (cm^2/min)	Dendritic web	20	8	30
Plasma deposition rate (Å/s)	a-Si:H	10	2	40
		Financial case		
Return on equity (%)	All	18	22	15
Debt/equity ratio	All	0.3	0.2	0.5
Debt interest rate (%)	All	14	16	12
Average cost of capital (%) (derived from other inputs)	All	17.1	21.0	13.5

were selected and reviewed by several organizations involved in the study, and it was recognized that the resulting module-price predictions were lower than those achieved at the time of the study, or, for the most part, even today. They represented a potential level of the price for high volume production with high conversion efficiencies. After determining with the model the key price drivers for each technology, other cases were defined to examine the effect of different values of the key drivers. Two cases, defined as optimistic and pessimistic and shown in Table 21.2, were used to compare with the base case. Base, pessimistic, and optimistic cases relating to material-cost parameters (process case) and cost-of-money parameters (financial case) were defined. Table 21.2 shows only the "key" parameters of the defined cases, that is, the parameters from the cases that had the greatest effect on price.

The range of required module prices associated with the full set of process-case parameters is provided in Figure 21.3 for all of the cell technologies. Within each of the process cases, the spread in module prices among the technologies is about 2:1, so that achievement of important processing parameters and conversion efficiencies has a large impact on their ultimate relative prices.

The effect of the financial case parameters on module price was determined to be in the range of about ±5% of the base case for all of the technologies. For example, Table 21.3 gives the required module prices for the Czochralski modules for each case. The range of prices for the process cases due to variation in material costs ($3.46–$1.22) is much greater than the variation due to the financial-case parameters ($1.98–$1.80).

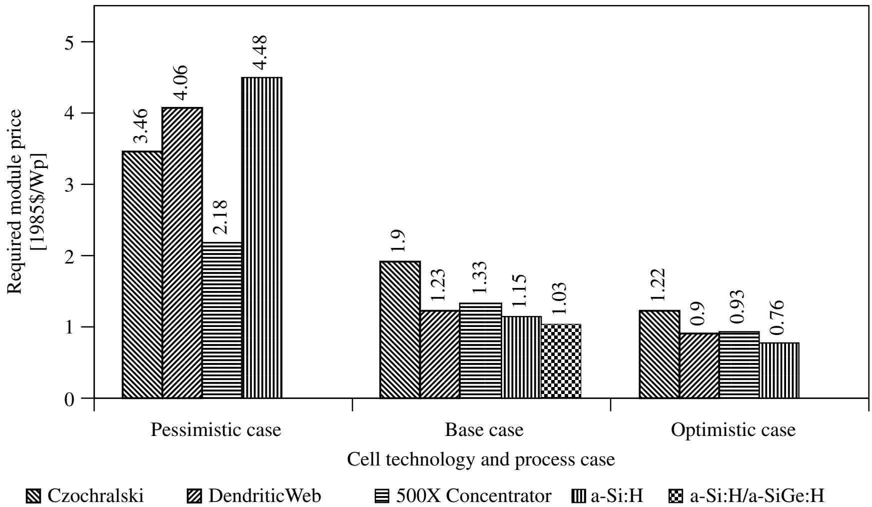

Figure 21.3 Required module price for silicon-cell technologies [3]. Copyright © 2002. Electric Power Research Institute. EPRI AP-4369. Photovoltaic Manufacturing Cost Analysis; A Required Price Approach, Vol. 1, 2. Reprinted with Permission

Table 21.3 Czochralski module prices for process and financial cases (1985$/$W_p$)

		Process cases		
		Pessimistic	Base	Optimistic
	Pessimistic		1.98	
Financial cases	Base	3.46	1.90	1.22
	Optimistic		1.80	

This relationship results from the fact that material costs are a large fraction of the required module price, 44.2% for the Czochralski base case, whereas the cost of the required capital for machinery and equipment, which is usable over several years, is a much smaller fraction of the price.

A sensitivity diagram, such as Figure 21.4 for the Czochralski module, illustrates the relative effect of individual process or financial-parameter values on the required module price. Here, the module-price variations for each parameter are plotted with respect to the parameter expressed as a percent of its base-case value. The slopes of the lines are then the price sensitivity to each parameter. For the Czochralski module, the price is most sensitive to the achieved conversion efficiency and the unit cost of the silicon boule. The price is much less sensitive to the unit cost of the glass sheet, wafer thickness, and return on equity (a financial parameter equivalent to the profit for the module manufacturer). Sensitivities for the other cell technologies follow a similar pattern.

One of the most useful results of the study is the illustration of the trade-off between the silicon-utilization and cell-conversion efficiency as reflected in the module price. Figure 21.5 shows the effect of efficiency on the base-case prices for all five cell

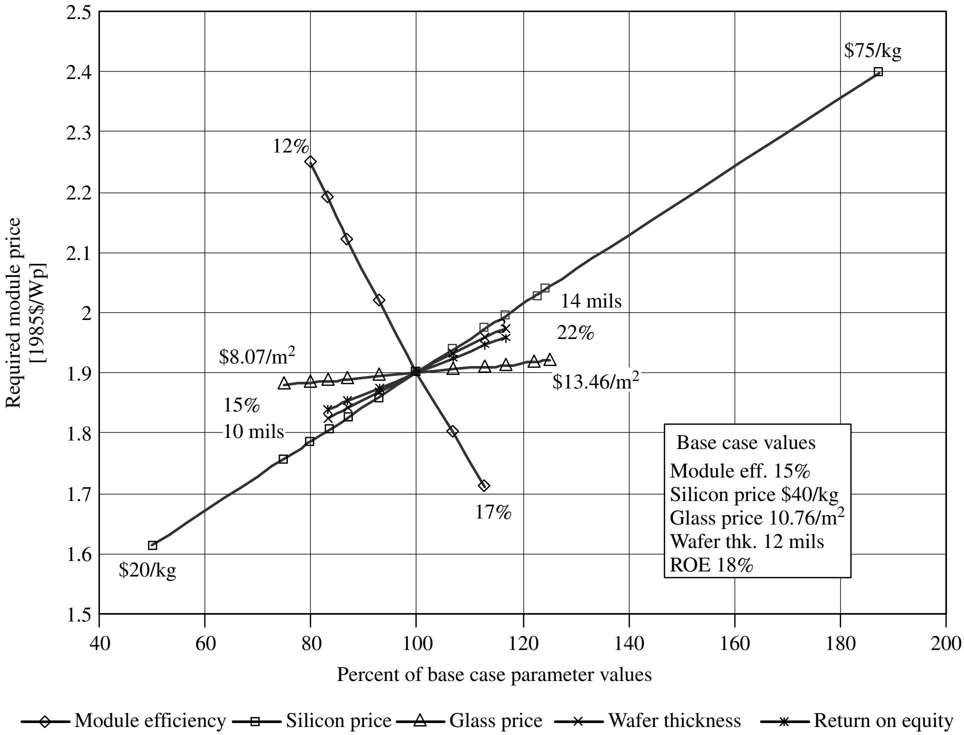

Figure 21.4 Sensitivity of Czochralski required module price to selected parameters [3]. Copyright © 2002. Electric Power Research Institute. EPRI AP-4369. Photovoltaic Manufacturing Cost Analysis; A Required Price Approach, Vol. 1, 2. Reprinted with Permission

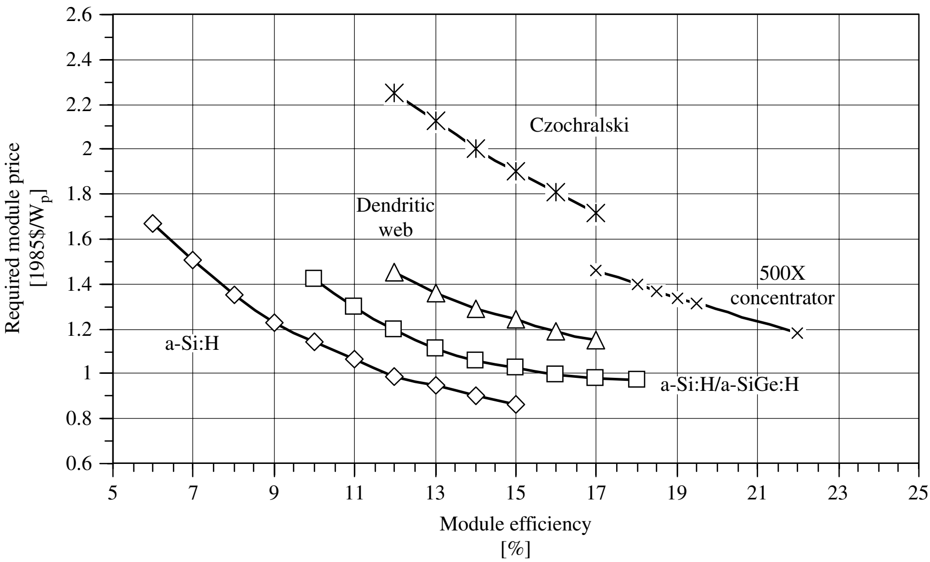

Figure 21.5 Effect of cell technology and efficiency on module price

technologies. Silicon requirements vary significantly with the choice of a cell technology and its associated cell-fabrication process. Cell-conversion efficiency is also significantly different among the cells made by different processes, and these efficiency differences are inherent in the cell structures. For example, the amorphous cells require much less silicon than Czochralski cells, but the latter have higher efficiency and require less module area to achieve the same rated capacity. How the module prices of the two cell technologies compare is also dependent on the cost of their fabrication processes. Some processing steps are unique to each cell or module as required by their structures and materials, but in other steps the processing is essentially the same. For example, the single- and tandem-junction thin-film cells have many common processing steps. Also, the encapsulation steps for several of these modules are the same.

The similarities and differences in the five cell/module technologies have important implications on cost, measured as $/W$_p$. In the case of cells fabricated from either Czochralski wafers or dendritic web substrates, the use of silicon for dendritic web cells is less than 20% of that used for Czochralski cells, and silicon is the single most costly material in both processes.

The dendritic web thickness was taken as about 5 mils, whereas the wafer thickness was 12 mils, and the wafers must be sawed from a boule with a kerf loss of 10 mils and an area loss because the boule is round. Dendritic webs are formed in a long strip with no kerf loss and very little area loss. The formation of the dendritic web substrate and the wafer is the primary difference in the two cell/module processes; the remaining steps to produce the cells and modules are essentially the same. The cell efficiency was taken as the same for the Czochralski and dendritic web modules.

Amorphous-silicon cells are produced by an entirely different process that results in a silicon cell that is about 1000 times thinner than the other two flat-plate cells. The "silicon" consumption (actually silane gas) is reduced to the point at which the glass substrate on which the cells are grown is the most costly item of material. However, a-Si cell efficiency has proved to be lower than that for the crystalline cells. In this study, base-case module efficiency using crystalline cells was taken as 15%, and the efficiency for the a-Si module was taken as 10%. For the tandem-junction a-Si cell/module, additional film-growth steps are added to the process, which consumes additional silane, but the material cost is still small. The efficiency for the tandem cell was taken as 15%. The module-fabrication steps are also different from the crystalline-cell modules because all of the cells for a module are deposited on one piece of glass, and cell interconnections are defined by scribing rather than soldering copper straps between cells.

For the concentrator module, the cell is fabricated on Si wafers on equipment comparable to the Czochralski flat-plate cell, but its fabrication was not modeled for this study. There are some cell-design differences that change the cell fabrication somewhat. Instead of modeling with STAMPP, a base-case cell cost of $2/cell was used for a 1-cm square cell. For comparison, the Czochralski and dendritic web cells were 10-cm square. The fabrication of the 48-cell Fresnel module was modeled as an automated parts fabrication and assembly operation. Since the concentration ratio for the module was 500X, the basic trade-off between the concentrator and flat-plate modules is the more complex mechanical structure of the concentrator with much less silicon-cell area compared to the simpler flat-plate structure with more silicon-cell area. The concentrator also had a base-case conversion efficiency of 19.2%. Inherent in the comparison is also the difference in solar insolation applicable to the two technologies.

The required module prices in Figure 21.5 show a significant overlap of all of the cell technologies except Czochralski, which is consistently higher than the others. It is clear that the module-price, in $\$/W_p$, comparison among any of the four less-expensive modules depends greatly on the efficiency achieved. A horizontal line representing, for example, $\$1.20/W_p$ corresponds to about a 9% efficient single-junction amorphous module, but requires about 12% efficiency for the tandem-junction amorphous module, because the latter is more expensive to produce. The same rationale applies to the dendritic web and concentrator modules. The module price range for the Czochralski single-crystal wafer cells does not overlap the other cells, and, for the input data used in the study, it would always be more costly than the others. In hindsight, single-crystal and polycrystalline cells continue to be the most prevalent commercial technology, which perhaps is due to their having achieved more of their performance potential in volume production than have the other technologies. The wafer-cell technologies have simplicity on their side, even at the disadvantage of higher silicon use.

21.2.3.2 Cost of electricity for utility-scale PV plants

A study by the EPRI [4] encompassed both manufacturing-cost modeling and financial analysis for utility-scale PV plants. The study included three systems: a heliostat field focused on a central receiver incorporating a water-cooled silicon-cell array, a field of Fresnel lens concentrator arrays using silicon cells, and a field of fixed-tilt flat-plate module arrays using CIS cells. Brief results of the Fresnel system are given here to illustrate module-price analysis and system-cost development. Total energy costs for all three plants are also given later to illustrate the economic analysis for the three systems.

An extensive design study defined a 50-MW Fresnel system, and included specifications for a 500X Fresnel concentrator module having 48 Fresnel lenses per module, each lens being about 45-inches square with one back-contact Si cell mounted below it. A glass secondary lens was mounted between the Fresnel lens and the cell. The cell efficiency was taken as 27.4%, and module efficiency as 20.7%. Each cell had a passive heat dissipator on the back surface of the assembly. The basic module structural element was a molded plastic box supporting 4 cell/lens units, and 12 of these were assembled into a module (i.e. 48 cells/module). Sixty of these modules were mounted on a tracking structure to form an array. The total array field had 3390 arrays and the plant covered 700 acres.

Manufacturing of the cell and module assembly was modeled with the STAMPP program described previously. It was assumed that the modules would be produced over two years. The Stanford Advanced Back Contact cells were fabricated on 150-mm silicon wafers using conventional cell-fabrication processes. Table 21.4 summarizes the results of the module-cost modeling for a base case, whose results were input to the plant cost computation. The top section of the table shows some basic operating and financial parameters for the module business, and gives the computed module required price as \$320.08 each (1990\$), or $\$1.30/W_p$. Such a cost was indeed optimistic for the time the study was conducted, but it did represent a relatively high annual production volume. A significant amount of automation was employed, especially in the assembly of the module. A breakdown of module cost (taken from the income statement of the business) is shown in

Table 21.4 Fresnel module price summary, base case [4]

Annual plant production (module/year)		101 700
Unit price (1990$/module)		320.076
Base year		1989
Simulation length (years)		10
Plant capacity factor (%)		100.000
Annual plant operating time (h/year)		8519
Maximum number of shifts per working day		3
Required return on investment (fraction)		0.200
Debt to equity ratio (fraction)		0.250
Combined fed/state income tax rate (fraction)		0.340
Product price components in first full year of production (end of year dollars)		
Component	1990$/module	% of total
Annual sales	320.076	100.00
Annual manufacturing expense	289.366	90.41
Annual direct material expense	219.758	68.66
Annual direct labor expense	14.592	4.56
Annual manufacturing overhead	55.016	17.19
Net annual work-in-process	0.297	0.09
Net finished goods inventory	0.000	0.00
Selling & administrative expense	9.155	2.86
Corporate income taxes payable	6.679	2.09
Excess revenue (interest earned)	12.966	0.50
Annual net income	1.612	4.05
Initial work station equipment cost ($1989)		4 260 447
Initial facility cost ($1989)		3 158 375
Total manufacturing area (sq ft)		39 453
Total nonmanufacturing area (sq ft)		11 532
Total facility area (sq ft)		50 985
Total land cost ($1989)		124 036
Total direct manufacturing labor (# workers)		56
Total indirect manufacturing labor (# workers)		19
Total indirect nonmanufacturing labor (# workers)		43
Total plant labor (# workers)		118

the center section of Table 21.4. Direct manufacturing costs are about 90% of the total cost, with materials accounting for 69%. The 17% contribution of manufacturing overhead is composed of manufacturing supervision labor, equipment and facilities depreciation, plus other smaller items, but about half of the 17% is the R&D budget assigned to the business, which corresponds to 8.5% of sales. In the bottom section of Table 21.4 are the costs of process equipment and buildings, and the number of people employed in the business.

Any study of future costs benefits from an examination of the sensitivity of the result to different values of critical input parameters, because it contributes to understanding the

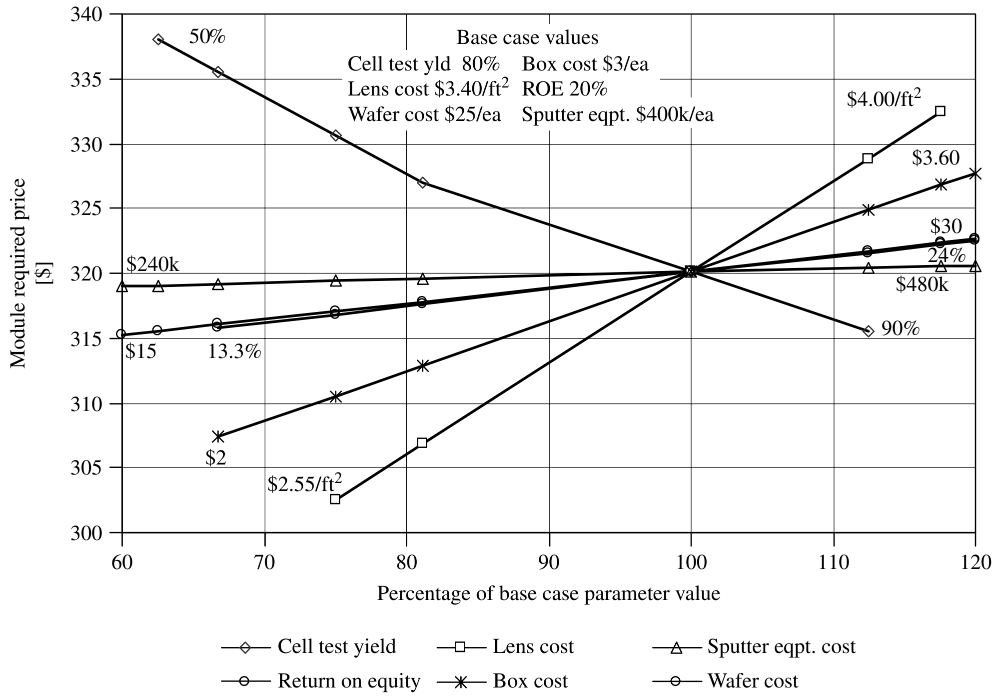

Figure 21.6 Effect of selected parameters on Fresnel module price (1990$) [4]. Copyright © 2002. Electric Power Research Institute. EPRI TR-101255. Engineering and Economic Evaluation of Central-Station Photovoltaic Power Plants. Reprinted with Permission

risk in the choice of inputs. Figure 21.6 shows the effect of different values of certain materials, equipment, and financial costs on module required price. Cost components are plotted on the abscissa as a percentage of their base case value, which means that the slope of the lines represents a relative sensitivity of module price to the parameter change (absolute values at the extremes are also shown for reference). The output of the STAMPP model identified the Fresnel lens and the molded box as the two largest material costs, at 31% and 17% of material costs, respectively. Silicon wafers, at 5%, were another significant cost. Sensitivities to a fairly wide range of these costs are shown, with the extreme variation in module price being less than 6%. By way of comparison, the price of the most expensive cell-processing equipment, sputtering, had a much smaller impact on module cost. This is a typical result in such studies, resulting from the depreciation of the equipment over several years. Cost of money, represented by return on equity (ROE), has about the same impact as wafer cost. Process yield for each workstation is a parameter in STAMPP. For cell manufacturing, the yield at cell test is critical, and the base case cell yield for the study was 80%. Figure 21.6 shows cell yield to have a large impact relative to some other parameters.

The total capital cost of the Fresnel lens plant in Table 21.5 reflects the accounting system of the study sponsor, EPRI. The $\$1.62/W_p$ cost of the PV modules includes shipping and installation, and is 50% of the total system capital cost. The installed array-structure cost brings the total collector cost to about 73.5% of the system cost. The power conditioning and balance-of-plant costs add another 5.5%, leaving about 20% of the cost

Table 21.5 Total capital requirements for central station plants [4] 3rd Quarter 1990$, Carrisa Plains Site

	Fresnel lens		Central receiver		CIS flat plate	
	[$(10^6)]	[$/Watt]	[$(10)^6]	[$/Watt]	[$(10^6]	[$/Watt]
Buildings, site improvement	1.20	0.02	1.9	0.04	1.23	0.02
Array structure	37.92	0.76			13.38	0.27
PV modules	80.80	1.62			66.91	1.38
Heliostat system			53.30	1.07		
Receiver system			18.80	0.38		
Receiver tower			6.30	0.13		
Power conditioning unit	5.92	0.12	4.30	0.09	5.85	0.12
Balance of plant	3.09	0.06	16.40	0.33	7.06	0.14
Master control system	0.12	0.00	0.80	0.02	0.08	0.00
Total field cost	129.10	2.58	101.80	2.04	94.50	1.91
Engineering. & const. Management	5.20	0.10	6.10	0.12	2.80	0.06
Owner's costs	5.40	0.11	5.40	0.11	2.90	0.06
Contingencies	14.20	0.29	19.70	0.39	9.80	0.20
Total plant cost	153.90	3.08	133.00	2.66	110.00	2.22
Escalation (mixed year dollars)	(2.90)	(0.06)	(2.50)	(0.05)	(2.10)	(0.04)
Total cash expended (mixed year dollars)	151.00	3.02	130.50	2.61	107.90	2.18
Allowance for funds during const. (mixed year dollars)	6.80	0.14	5.80	0.12	4.80	0.10
Total plant investment	157.80	3.16	136.30	2.73	112.70	2.27
Preproduction costs	3.20	0.06	2.90	0.06	2.30	0.05
Inventory capital	0.80	0.02	0.70	0.01	0.60	0.01
Land	0.20	0.00	0.30	0.01	0.20	0.00
Total capital requirement	162.00	3.24	140.00	2.80	116.00	2.34

associated with engineering, construction management, cost of money, contingencies, and so on. The contingency item accounts for uncertainties in system performance and unaccounted costs in the design. Later systems of the same design may avoid some of the contingency cost. The total system cost in Table 21.5 is equivalent to the present worth of capital expenditures during the construction of the systems. The central receiver plant and the CIS flat plate plant both turn out to have less-expensive collector costs than the Fresnel lens plant, and the resultant total capital requirements are also less by 14% and 28%, respectively. The central receiver plant has a forced convection, water-cooling system that adds significantly to the system cost relative to the other two plants.

The remaining steps in computing LEC (see equation (21.14)) are summarized in Table 21.6. The typical energy output was calculated from solar-insolation data and the performance parameters of the systems using computer codes. The energy outputs for

Table 21.6 Annual performance and energy cost summary for central station plants [4] Constant 1990$, Carrisa Plains Site

	Fresnel lens	Central receiver	CIS flat plate
Average annual performance			
Energy output (MWh)	140 100	125 000	112 000
Capacity factor	32.0%	28.5%	25.8%
Annual energy efficiency	18.8%	11.3%	9.9%
Annual expenses ($\$10^6$)			
Capital charge	16.69	14.42	11.95
Operation & maintenance expense	0.61	1.197	0.18
Total	17.30	16.39	12.13
30-year levelized energy cost ($/kWh)			
Capital charge	0.119	0.115	0.106
Operation & maintenance costs	0.004	0.016	0.002
Total ($/kWh)	0.123	0.131	0.106

the systems reflect both the efficiencies and the collector characteristics of the different system designs. The annual capital charge is the annualized amount of the total capital requirement, using a CRF of 10.2%. Levelized energy cost is the total annual expense divided by the annual energy output. It is interesting that the lowest LEC corresponds to the CIS flat-plate system that has the lowest efficiency and incorporates the simplest collector technology. (Cell efficiency for the CIS cell was taken as 15%.) The relationship among the LECs for the systems also points out that cell and module efficiencies, while very important in system performance, do not by themselves determine energy cost. Other system-design factors are also very important, and within limits, override the effect of efficiency on energy cost.

21.2.3.3 Gallium arsenide cells in power systems

GaAs cells have been developed and used extensively for space applications, but traditionally have been considered too expensive for terrestrial applications despite their high efficiency. These compound semiconductor cells are fabricated by epitaxial growth, either on GaAs wafers or on Ge wafers, the latter being a more recent development. The cost of GaAs wafers is a major factor in the cost of cells, and Ge wafers are projected to be less expensive by more than an order of magnitude. The question that arises is whether GaAs cells could be competitive with Si cells for utility-scale terrestrial systems, particularly if grown on Ge wafers. To address this question, the cost study in the previous section, as it relates to the Fresnel lens plant, was extended to determine the cost of energy for the same plant using GaAs cells of several different designs [5].

Two cells were considered: a single-junction GaAs cell, and a tandem-junction GaInP/GaAs cell. These GaAs cells are designed as concentrator cells, and could be considered for the same kinds of applications as the Si concentrator cells in the Fresnel lens

Table 21.7 GaAs cell and module price (1994$) [5]

Cell/wafer	Cell efficiency	$/Module (48 cells)	$/48 cells
SJ/GA-SC	25	741.14	459.94
	30	741.54	460.50
SJ/Ge-SC	25	447.01	156.52
	30	450.40	159.11
SJ/Ge-PC	25	404.19	111.28
	30	407.58	113.79
TJ/GA-SC	30	745.96	464.68
	35	748.56	466.99
TJ/Ge-SC	30	456.33	164.51
	35	456.31	164.90
TJ/Ge-PC	30	413.50	119.11
	35	413.49	119.51

Note: SJ = single junction; TJ = tandem junction; SC = single-crystal; wafer PC = polycrystalline wafer. © 1994 IEEE

module of the prior study [4]. The manufacturing processes for each cell were defined using three different wafers: single-crystal GaAs, single-crystal Ge, and polycrystalline Ge. Modules incorporating each of the six combinations were modeled using the same STAMPP model as for the Fresnel lens module in the prior study. Further, a range of cell efficiencies for the GaAs cells was examined because the GaAs technology was not as well developed as the Si technology. In order to compare the annual energy production from GaAs plants with Si plants, the number of modules required for a 50-MW plant was calculated and the cost of modules computed with STAMPP at the required volume, as shown in Table 21.7. The total capital requirements, as shown in Table 21.5 for the Si plant and adjusted to 1994$, were then scaled appropriately for the number of GaAs modules.

The price of GaAs cells, whether single- and tandem-junction, shown in Table 21.7 is heavily influenced by the choice of GaAs or Ge substrate. Cells grown on Ge-PC wafers are roughly four times less expensive than cells grown on GaAs-SC wafers. However, the prices of modules incorporating these cells differ by only a little less than a factor of two due to the fact that several substantial module-cost components are the same regardless of the cell structure. The least expensive module cost of $413.50 in Table 21.7 for TJ/Ge-PC cells compares to the $328.42 for a module incorporating Si cells (see Table 21.4, escalated to 1994$). Cell efficiency for the same cell structure in Table 21.7 has little effect on module price. Indeed, module price is, in some cases, just slightly higher for the higher efficiency cell than the lower one (e.g. SJ/Ge-PC at 25% versus 30%). This is a result of the modeling procedure in which the number of modules produced was just sufficient for the 50-MW power plant, being fewer at higher cell efficiency, and the allocation of elements of cost by the STAMPP model to a fewer number of modules.

The reduction in cell and module prices in Table 21.7 reflects a span of about 15:1 in wafer costs between GaAs-SC and Ge-PC wafers, as indicated in Table 21.8. When GaAs cells are grown on the GaAs wafer, the cost of the wafers is almost 60% of the module materials cost, but when a Ge-PC wafer is used, then the wafer contributes to only

Table 21.8 Module materials cost drivers, GaAs tandem-junction cells [5]

	Substrate (GaAs & Ge = 4″, Si = 6″)			
	GaAs	Single-crystal Ge	Polycrystalline Ge	Si
Wafer cost/each	$360.46	$64.37	$23.62	$29.94
Material	*Percentage of total module materials cost*			
Wafer	59.8	20.4	8.6	5.3
Module box ($3.59/each)	6.9	13.2	15.1	17.4
Heat sink ($0.52/each)	4.0	7.7	8.8	10.1
Fresnel lens ($4.07/ft^2)	12.2	23.3	26.8	14.3

Source: © 1994 IEEE

about 9% of the module materials cost. The latter case is very similar to the materials cost contributions for the Si module, where the wafer cost is not the largest single contributor. Using Ge wafers would thus be a major step in making GaAs cells competitive.

When the module prices in Table 21.7 are incorporated into the 50-MW power plant, capital requirements (Table 21.5) by adjusting these costs for the changes in field size resulting from the GaAs conversion efficiencies, the cost of energy generated, expressed as LEC, can be calculated for the various cell structures in Table 21.7 (see Figure 21.7). These GaAs-based energy-production costs are compared to that of Si-based energy-production costs from the previous study [4] as summarized in Table 21.6. Since none of the GaAs module prices, ranging from $741 to $413, is as low as the Si module price of $328, the LECs in Figure 21.7 essentially show the trade-off of the more efficient (27.5% to 35%) but higher cost GaAs modules with the less efficient (27.4%) but lower

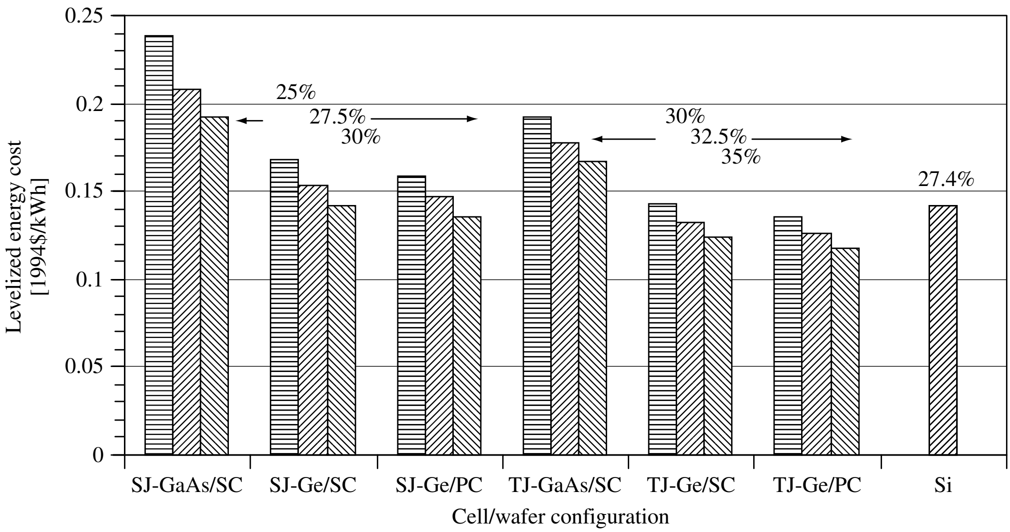

Figure 21.7 Cost of energy produced by 50 MW central station Fresnel lens plants using GaAs cells [5]. © 1994 IEEE

cost Si modules. The most costly GaAs technology (SJ/GA-SC), even at its highest projected efficiency of 30%, has an LEC of $0.192/kWh compared to the LEC of the Si technology of $0.142/kWh. The least-costly GaAs technology (TJ/Ge-PC) has an LEC of $0.118/kWh at its highest efficiency of 35%, which is less than the Si LEC. The slightly more costly TJ/GA-SC technology still has a lower LEC ($0.124/kWh at 35%) than the Si module, and this GaAs structure using the single-crystal wafer is more likely to achieve the 35% efficiency than the polycrystalline wafer cell.

21.3 ENERGY PAYBACK AND AIR POLLUTION REDUCTION

PV systems convert the free solar energy resource into valuable electric energy. However, it has long been noted that energy is consumed in the manufacture of PV conversion hardware. That is, there is an energy cost to produce energy. The mining, refining, and purification of semiconductor materials is energy intensive, and energy is consumed in the manufacture of all the other materials in a PV system, such as glass, steel, aluminum, copper, and plastic. In addition to the energy content of the materials incorporated directly in the module, support structures, and balance of system (BOS) components, there is an energy content in the equipment that produces all the PV system components. Energy is also consumed in transporting and erecting a PV system at its operating site. During the life of a PV system, usually taken as 20 to 30 years, energy is produced as a return on the energy "invested" in its creation. The long-raised question is: how much more energy does the PV system generate than it takes to produce it; or, is there a net energy benefit to society from PV systems? The answer is usually stated as "energy payback," which is the number of years that is required to repay the energy content of the PV system with its delivered electricity. Energy payback for PV systems, measured in years, should ideally be a small fraction of the system life in years. In fairness to PV, it should also be noted that fossil energy systems, in addition to the energy consumed as they operate to produce electricity, also have an energy content in their power-plant hardware. In addition, the fuel itself has an energy content associated with the exploration, development, recovery, and transportation to the generation site. Thus, the terms of comparison for energy payback between PV and other systems need to be carefully defined if they are to be meaningful.

The energy-payback question needs to be differentiated from whether a PV system pays for itself economically (financially), which is a primary subject of this chapter. The question of economic benefit is adequately answered when the cost of all materials, equipment of production, and capital are accounted for. These costs include the cost of the energy content of all the elements of the system. Given that economic criteria are met, the energy payback question is essentially an ecological one; that is, does the creation of PV systems that generate substantially more energy than is consumed to produce them represent a wise use of fossil resources? A related issue is the reduction in greenhouse gases that results from the generation of electricity with PV rather than with fossil-fuel-based generation. If governments impose financial penalties on fossil generation or give credits for solar generation, then financial benefits can be introduced into the economic evaluation. To a degree this is implicit in the process when, for example, the cost of exhaust scrubbers for fossil plants is included in the economic comparison. Moreover, if solar energy is the source for producing PV systems, the ecological consequences are diminished. Given the small amount of PV generation capacity in service today relative to other electric generation capacity, the primary concern for energy payback is in long-term energy planning in relation to ecological impact.

The issue of energy payback has been examined quantitatively, and a good bibliography is given in [6]. Energy payback is determined by the four basic factors mentioned below:

- The design of the PV system, including all components
- The location of the system
- The life of the PV system
- The portion of the manufacturing energy-consumption chain included in the payback.

System design determines the system conversion efficiency and system power level, as well as defining the energy content of the hardware. The system location determines the incident energy for the system, which, coupled with the system life, determines the total energy delivered by the PV system. The total energy content of the PV system depends on just how far back in the energy chain the analysis goes. For example, does the chain go back to the mining, transportation, refining, and fabricating of a material, and include every piece of equipment used at every link of the chain? In most cases, PV material energy content is based on prior studies of the energy content of basic materials. Special considerations are sometimes incorporated; for example, much of the crystalline PV production is currently based on using scrap-refined Si from the microelectronics industry, so it may be reasonable to ignore the energy content of the scrap material.

In a summary of energy payback studies, the US National Renewable Energy Laboratory (NREL), states that "(E)nergy payback estimates for rooftop PV systems boils down to 4, 3, 2, and 1 years: 4 years for systems using current multicrystalline-silicon PV modules, 3 years for current thin-film modules, 2 years for future multicrystalline modules, and 1 year for future thin-film modules." These data assume a 30-year life. Multicrystalline modules have a longer energy payback because they have a much larger content of silicon than thin-film modules. Shorter payback for future modules is predicated on improved manufacturing processes and higher efficiencies.

NREL credits these results to the Dutch researcher Erik Alsema [7]. His data are based on estimates of 600 kWh/m^2 for the near-future, frameless, single-crystal silicon PV modules and 420 kWh/m^2 for multicrystalline modules. With a 12% conversion efficiency and a solar insolation level of 1700 kWh/m^2/year, Alsema calculated the 4-year payback for current multicrystalline modules. The future payback of 2 years for multicrystalline modules was based on a 14% efficiency and solar-grade silicon feedstock.

For thin-film modules, amorphous-silicon paybacks are a good proxy for all material systems (including copper indium diselenide, cadmium telluride) because the major energy content is in the substrate, usually glass, and the deposition process plus other facilities. The films are so thin that they have relatively little energy content [8].

Knapp and Jester [6] examine the energy payback for both actual copper indium diselenide (CIS) and single-crystal silicon processes and modules produced using measured data. The data that were collected from plants operated by Siemens Solar Industries and reported in [6] assume that the CIS plant operated at capacity. Energy content of production equipment, production facilities, and transportation of goods to and from the facility were excluded from the result. Using a solar insolation of 1700 kWh/m^2/year, and assuming an 80% correction for the system losses, the single-crystal silicon module had an energy payback of 4.1 years and the CIS module's payback was 2.2 years.

Given the predicted energy paybacks of, say, 1 to 5 years for PV systems, and their life of up to 30 years, payback is not a negligible factor in the overall energy-planning process, but neither is it a prohibitive one. Gradual improvements in conversion efficiency and improvements in manufacturing techniques can further reduce its impact over time.

The literature that addresses energy payback also addresses the contribution of PV systems in reducing greenhouse gases [7, 8]. "An average US household uses 830 kWh of electricity per month. On an average, producing 1000 kWh of electricity with solar power reduces emissions by nearly 8 pounds of sulfur dioxide, 5 pounds of nitrogen oxides, and more than 1400 pounds of carbon dioxide. During its 28 years of clean energy production, a rooftop system with 2-year payback and meeting half of a household's electricity use would avoid conventional electrical plant emissions of more than half a ton of sulfur dioxide, one-third of a ton of nitrogen oxides, and 100 tons of carbon dioxide." (Though not stated, we assume these comparisons are of solar versus coal-fueled generation.) Again, if the cost of removing these from the conventional emissions is quantified, the cost saving can be included in an economic assessment.

21.4 PROSPECTS FOR THE FUTURE

Photovoltaic cells, modules, and systems have undergone intensive development in the 25 years immediately prior to the twenty-first century. Significant improvements in performance and reductions in cost per unit area have been made. The variety of PV cells and module technologies commercially available or under development has expanded greatly, although crystalline-silicon technology still predominates. Cost-effective applications that capitalize on the unique characteristics of PV systems have been implemented. Many other applications have been installed that benefited from subsidies from utilities, government, or economic-development institutions. A lot of progress has been made, and yet PV supplies only a tiny fraction of the electric generation market.

A recent survey [9] by *Photon International* magazine puts the annual worldwide production of Photovoltaics at 401.4 MW$_p$ in the year 2001. There are about 59 PV module manufacturers worldwide. However, the industry has lost more than US$3 billion over its first 25 years, according to the President and CEO of Siemens Solar in 1998[10]. He further states that two-thirds of the industry is still dependent on some kind of subsidy. Europe, Japan, and the United States each supply major portions of this production. The corporate landscape has been in a constant state of change over these years. Many small companies started up and a few large corporations entered the business. Many of the smaller firms have been absorbed by large corporate conglomerates, but a few have managed to stay in the business and grow. In recent years, some of the world's major corporations have become major players in the PV industry. The top ten producers in 2001 were listed as follows [9]:

1. Sharp (a major Japanese electronic-equipment maker, their solar cells are primarily integral to electronics products) 74.0 MW$_p$

2. BP Solar (a unit of British Petroleum, that merged with the US firm Solarex and presently has plants in US, Spain, Australia, and India) 54.4 MW_p
3. Kyocera (a major Japanese electronics, equipment, and materials company) 54.0 MW_p
4. Siemens and Shell Solar GmbH (investments by German/Dutch conglomerate Shell and Siemens AG whose main production is in the US) 48.3 MW_p
5. AstroPower (independent US manufacturer) 26.0 MW_p
6. RWE Solar (a unit of the German Utility RWE that merged with ASE Americas 22.7 MW_p
7. Isofoton (independent Spanish manufacturer of PV and solar thermal technology) 18.7 MW_p
8. Sanyo (a major Japanese maker of electronic consumer products, semiconductors, batteries, etc; PV products made by Solec International division) 16.0 MW_p
9. Mitsubishi (a Japanese conglomerate providing a wide range of products and services) 14.0 MW_p
10. Photowatt (a unit of Matrix Solar Technologies, owned by a Canadian corporation ATS) 13.5 MW_p.

Despite the changes in the makeup of the industry, progress has been sustained by gains in performance and reductions in cost. PV module prices in $/$W_p$ declined by an order of magnitude over the nearly 20-year period ending in 1994[11]. This experience, shown in Figure 21.8, is based primarily on data for crystalline-silicon modules, but is said to be representative of other flat-plate module technologies as well. The projection beyond 1994 is based on a fit of the data for module price versus cumulative

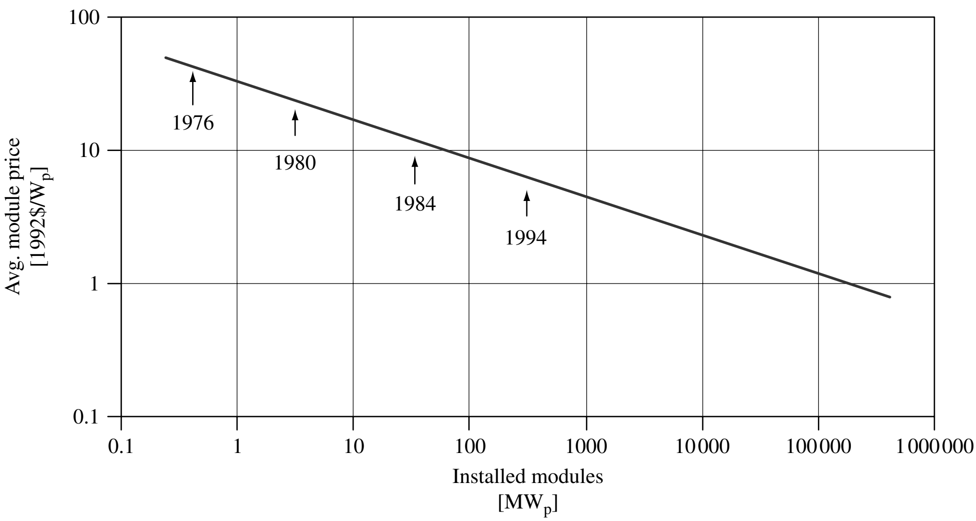

Figure 21.8 PV module price trends. Adapted from [11]. Copyright © 2002. Electric Power Research Institute. EPRI TR-109496. Renewable Energy Technology Characterizations, Topical Report

production. Significant departures from the projection might result from new technological development, such as thin-film modules or concentrator technology.

Some recent experiences [12] with PV systems with capacities in the range of 70 to 236 kW_p showed that system costs dropped by 14% from 1996–1997 to 1998–1999 (\$9.77/W_p to \$8.46/W_p). These systems included both fixed and one-axis tracking systems, which were mounted both on buildings and on the ground, and included modules and inverters from several manufacturers. Three of the most recent projects had installed costs below \$7/W_p.

Siemens has stated [10] that it is planning on a long-term annual growth rate of 15% for installed PV. Their projection is that a 15% to 25% rate would result in PV contributing to 1% of the world's electricity between 2025 and 2040, which they estimate as 300 TWh in 2025. They state that one-third of this energy could provide for the basic needs of two-billion people not served by a grid.

Another view of the potential for PV can be gained from some figures published by the US government. Recent progress and long-term goals for the US PV program [13] are shown in Table 21.9. Meeting these goals would increase cumulative US sales by the year 2030 to 20 times the year 2000 level, and correspond to about a 12% compounded annual rate of sales growth. The average annual sales from 1996 to 2000 would be about 65 MW/year, and from 2001 to 2030 would be roughly 315 MW/year. The US share of the world market for PV was about 41% in 1995[13]. If this share was maintained till 2030, the cumulative capacity would be about 25 GW. Assuming an average of 2000 h/year of sunlight, the annual generated energy would be 50 TWh by 2030. This is substantially lower than the Siemens estimate given above, but the difference is largely explained by the difference in the 12% annual growth rate and the Siemens estimate of 15% to 25%. Starting at the same 500-MW cumulative sales in 2000, using a constant 41% market share and 2000 h/year of sunlight, a 15% growth rate results in about 80 TWh/year of generated energy. Using a 25% growth rate, the energy is about 645 TWh. There is obviously a lot of uncertainty in making such projections, and the truth no doubt lies somewhere in the range of these estimates.

Some additional insight into the potential contribution of PV to the world's electric-energy needs can be had from data published by the US Energy Information Administration [14]. The world's net electricity consumption in 1999 was 12 833 TWh. Of this total, industrialized countries consume 59%, eastern Europe and the former Soviet Union, consume 11%, and developing countries account for 30%. If the cumulative PV capacity

Table 21.9 Photovoltaic progress and program goals (1995\$) US department of energy [13]

	1991	1995	2000	2010–2030
Electricity price (¢/kWh)	40–75	25–50	12–20	<6
Module efficiency[a] (%)	5–14	7–17	10–20	15–25
System cost (\$/W_p)	10–20	7–15	3–7	1–1.5
System lifetime (years)	5–10	10–20	>20	>30
US cumulative sales (MW)	75	175	400–600	>10 000

[a]Range of efficiencies for commercial flat-plate and concentrator technologies

in 2000 was 1220 MW (500 MW divided by 41%), an estimate of the energy generated will be 2.4 TWh, or about 0.02% of the world consumption. The projected average annual growth of electricity consumption over the period 1999 to 2020 in [14] is 2.7% worldwide, resulting in consumption of 22 230 TWh in 2020. Extrapolating this to 2025 as 25 398 TWh, the contribution of PV at 300 TWh would be 1.2%. While this is a small fraction, it still could, as the Siemens article points out, make a significant contribution to the lives of people where conventional grid-connected electricity is not available.

Looking at these varied projections of growth in PV sales, it is clear that the penetration of the future electricity market by PV systems is difficult to predict. It depends on many factors whose outcomes are uncertain, among them being the following factors:

- Continued progress in performance and cost reduction of PV systems. This is perhaps the most certain of the factors to be achieved, assuming that the deep-pocket firms now engaged in PV system development continue to be involved. Participation by government and industry associations through support of research and development will also contribute to this factor.
- Increase in the cost of fossil fuels. Numerous predictions made in the past of the cost of oil rising well above US$30 per barrel have failed to materialize on any consistent basis. The price of oil is a strong determinant of the cost of electricity that competes with PV electricity. The price of oil, largely determined by the international cartel, can only be raised so far without decreasing their market size. Major new fields in the Caspian Sea area or elsewhere will be an influence if they materialize, but such finds will become less likely over time.
- Increases in environmental costs for fossil-fuel-based electricity. Global warming concerns may prompt added costs of production due to greenhouse gas control or regulatory constraints or restrictions on competing uses, especially as the energy use of developing nations goes up. These factors will make PV more competitive.
- Accommodation of users to the variable character of the PV source. PV delivers energy when the sun shines, but there is much demand at other times. This characteristic can be overcome by the integration of PV into utilities, by sharing PV capacity among groups of users (a utility of a different sort), by adding storage to the PV system (e.g. electric storage batteries, hydrogen production and storage, hydroelectric storage), or by lifestyle changes. All of these are possible, but each accommodation has its own barriers.
- The need for off-grid electric power is very large and the capacity required for individual sites is usually small. PV systems are more modular than almost any other source, and they provide insurance against rising fossil-fuel prices. If ways can be found to make them affordable, PV has an enormous off-grid market.

All of these projections suggest that PV systems will continue to increase their market penetration and make a useful contribution to energy supply over the next several decades. The likelihood of their becoming an economically significant fraction of the energy supply, say 5% or more, within the next 20 to 30 years appears to be small at this point. Such an event will require fundamental changes in the way energy is delivered, and those changes will have to be driven by economic and environmental forces beyond the control of the PV industry.

REFERENCES

1. Smith G, *Engineering Economy: Analysis of Capital Expenditures*, 2nd Edition, Chap. 4, The Iowa State University Press, Ames, IA (1977).
2. Stevens Jr. G, *The Economic Analysis of Capita Investments for Managers & Engineers*, Chap. 5, Reston Publishing, Reston, VA (1983).
3. Whisnant R, Wright S, Champagne P, Brookshire K, *Photovoltaic Manufacturing Cost Analysis; A Required Price Approach*, Vol. 1, 2, EPRI AP-4369, Electric Power Research Institute, Palo Alto, CA (1986).
4. Stolte W, *Engineering and Economic Evaluation of Central-Station Photovoltaic Power Plants*, TR-101255, Electric Power Research Institute, Palo Alto, CA (1992).
5. Whisnant R *et al.*, "Silicon and GaAs/Ge Concentrator Power Plants: A Comparison of Cost of Energy Produced", *Proc. IEEE First World Conference on PV Energy Conversion*, 1103–1106 (1994).
6. Knapp K, Jester T, "An Empirical Perspective on the Energy Payback Time for Photovoltaic Modules", *Proc. Solar 2000 Conference* (Madison, WI, 2000).
7. Alsema E, "Energy Requirements and CO_2 Mitigation Potential of PV Systems", *Workshop, Proceedings, Photovoltaics and the Environment* (Keystone, CO, 1998).
8. *Energy Payback: Clean Energy from PV*, NREL Report No. FS-520-24619, National Renewable Energy Laboratory, Golden, CO (1999).
9. Schmela M, *World production for solar cells grew 40% in 2001*, Photon International (magazine), 38–43 (March 2002).
10. Oswald G, "The PV Industry Moving into the Solar Century", *2nd World Congress on Photovoltaic Energy Conversion* (Vienna, Austria, 1998).
11. DeMeo E, Galdo J, *Renewable Energy Technology Characterizations*, Topical Report, TR-109496, U.S. Department of Energy, Electric Power Research Institute, Washington, DC, USA (1997).
12. *Large Systems Cost Report: Cost Analysis for 70 kW and Larger TEAM-UP PV Installations*, Solar Electric Power Association, Washington, DC (2000).
13. *Photovoltaics the Power of Choice: The National Photovoltaics Program Plan for 1996–2000*, U.S. Department of Energy, Washington, DC.
14. *International Energy Outlook 2001*, U.S. Energy Information Administration, Washington, DC (2001).