CHAPTER 7
Economics

Owning a power plant is philosophically appealing. Who wouldn't want to be independent of the local utility? Who wouldn't like to become more self-reliant, to become more insulated from future energy price hikes? But for most people the decision to invest in a small grid-connected power plant is based on sound economics, not philosophy.

A project's economic viability is judged by comparing its costs and benefits. Estimating project costs is much the simpler task. Equipment suppliers and contractors can provide specific cost estimates (although the risk of construction cost overruns remains). The terms of the project's financing are known before it is started. The term of the loan, the interest rate, the repayment schedule, the down payment and any other pertinent information will be specifically described in the contract before construction begins.

The project's benefits will be much harder to calculate. They consist primarily of guesses about the future. Even tax benefits may be uncertain because federal and state tax laws can change. The investor wants not only to maximize profit but also to minimize risk. A risk is a measure of uncertainty, and investments in small power plants present a greater array of uncertainties than other business investments. Will the technology function as expected? Will its availability factor meet manufacturers' claims? The cost of electricity from a machine operating at a 40 percent rather than an 80 percent availability factor is twice as high.

Will fuel be available in the quantity expected? Insolation varies relatively little from year to year but may vary significantly in any given month. This can affect project revenues if the qualifying facility (QF) operates under a time-of-day buyback rate. Wind regimes and stream flow rates can vary tremendously from year to year, greatly affecting the project's cash flow. Lean years must be expected along with the bounties of strong winds and heavy rainfall or snows.

What will the price of fossil fuel be in the future? The cogenerator using fossil fuels must not only project the future price the utility will pay but also the future price of fuel oil or natural gas consumed by the system. If the cogenerator is selling electricity to a utility whose marginal power plant is fueled by oil, while the cogenerator uses natural gas, the economics of the project will depend primarily on the relationship between future oil and gas prices. A cogenerator selling electricity to a utility with no future construction plans, that is, retiring its remaining oil- or gas-fired peaking plants to operate completely on coal or uranium, may find that profits in the early years will be eaten up by the higher cost of natural gas compared to coal in later years.

The greatest degree of uncertainty is in the level of future buyback rates. One study completed in mid-1982 for the city of Boulder evaluated the economics of various electric generation projects. It concluded that buyback rates under the Public Utility Regulatory Policies Act (PURPA) could range from slightly more than a penny to about 7.5¢, depending on the methodology used by the public service commission and the local utility. This range was possible even though all data on the cost of production to the utility was known. Imagine the possible variations when one is trying to project buyback rates 5 or 15 years into the future.

The investor often discovers the need to trade off profit for certainty. The uncertainty of future buyback rates can be diminished by negotiating a long-term contract with the utility. However, to gain such a contract, the QF must be willing to give up something. The price of gaining a long-term contract is often reduced profits. Long-term contracts might not have an escalator clause, but they might guarantee a base price for electricity. The base price in effect guarantees the investor a certain rate of return (assuming the technology operates as expected). In return the investor gives up the opportunity of making a much larger profit if future avoided energy costs should rise dramatically.

Insurance policies can also reduce some uncertainties. The manufacturer may be willing to guarantee the reliability of the technology, provided the buyer purchases a service contract. One cogenerator in New England took out an insurance policy to protect against the possibility that oil prices would rapidly *decline*. A wind-farm developer in Hawaii managed to purchase an insurance policy from Lloyds of London to insure that the wind would blow a certain portion of the time at a minimum speed.

Insurance policies are not cheap. An insurance company analyzes the risks involved and sets premiums to cover such probabilities plus to earn a healthy profit for itself. By spreading the risk over many ventures, the insurance company presumably can provide coverage at a lower price. But these premiums are expensive, which means that some projects may buy certainty at such a high price that the project is no longer economically viable.

A Simplified Guide to Energy Economics

The major determinants of the economics of independent production are: (1) the installed cost per kilowatt of capacity, (2) the capacity factor, (3) the financing terms, (4) the utility buyback rate or displaced cost of buying utility power and (5) the tax benefits.

The impact of each of these factors will be explored later in some detail. Here some simple rules of thumb are presented that can provide the potential producer with a good initial perspective.

The first step is to estimate the cost per installed kilowatt of capacity. For wind-power systems, this will be between $1,500 and $3,500, largely depending on the size of the system. Larger systems have lower per-kilowatt costs. For photovoltaic systems, the current installed cost is about $10,000 per peak kilowatt. Unlike the other technologies, this price is dropping rapidly and may be as low as $5,000 by 1985. Photovoltaic system costs do not significantly decline for larger installations. Hydroelectric system costs are more variable, because they depend not only on the size of the facility, but on the need for a dam, the spillway length, cost of the powerhouse and land acquisition costs for roadways as well. Costs range from $2,000 to $6,000 per installed kilowatt. The installed cost of a cogeneration plant is $1,000 to $2,000 per kilowatt.

To estimate the amount of electricity generated from these different technologies, a capacity factor, that is, the percentage of the year the generator will be operating at full rated capacity, must first be developed. An earlier section examined a chart developed by C. G. Justus (see figure 6–8) that estimated capacity factors for wind turbines at different rated wind speeds and in different wind regimes. Capacity factors for wind turbines will be in the 15 to 35 percent range. An average would be about 20 percent. For photovoltaics, you can assume that the system will receive the equivalent of full sun for 4 to 6 hours of each day, averaged over the year. That means a capacity factor of 16 to 25 percent. Assuming the owner has sized the hydroelectric system appropriately (that is, one that is based on the best year-round production of electricity) the capacity factor should be 75 to 90 percent. A cogeneration system can operate at full capacity 90 to 95 percent of the time.

Using these capacity factors, the conclusion is that a 1-kilowatt (kw) wind turbine will generate approximately $8{,}760 \times 0.20 = 1{,}752$ kilowatt-hours (kwh) per year. A 1-kw photovoltaic array will generate about the same. A 1-kw hydroelectric system will generate $8{,}760 \times$

0.85 = 7,446 kwh per year. A 1-kw cogenerator will generate 8,760 × 0.95 = 8,322 kwh per year.

To discover the annual cost of owning the technologies, assume the owner has obtained 100 percent financing based on a 15-year, 12 percent loan. Thus the cost per $1,000 is $143 per year (principal plus interest). If the wind machine costs $2,500 per installed kilowatt, the annual carrying costs are $356. Assuming the turbine generates 1,732 kwh per kilowatt of installed capacity, the cost per kilowatt hour is 21¢. For photovoltaics, assuming a $10,000 installed cost, the cost per kilowatt hour generated is 82¢. A hydroelectric facility costing $4,000 per kilowatt will generate electricity at a cost of 7¢ per kilowatt-hour. The calculations for cogeneration are more complicated because fuel must be purchased for its operation.

What these calculations show is that without taking into account tax benefits or future increases in energy prices, the owner of a hydroelectric facility who is receiving more than 7¢ per kilowatt-hour from the utility (or who can use the electricity internally to displace electricity that would have cost more than 7¢ to purchase from the utility) would be making money from the beginning. For the wind machine owner to break even, the utility must be paying 21¢ per kilowatt-hour and for the photovoltaic owner, 84¢ per kilowatt-hour.

These figures should worry only those owners who cannot take advantage of the tax benefits realized from owning their own power plant. For example, the residential user receives a 40 percent tax credit for owning a renewable-based technology. Assuming the owner does not exceed the tax credit ceiling, this lowers the actual cost to the wind machine owner to 12¢ per kilowatt-hour and to the photovoltaic system owner to 50¢ per kilowatt-hour. In addition, the owner can benefit from the tax deductions derived from the interest paid on the loan. In the preceding example, of the $143 paid in the first year for each $1,000 borrowed, $119 is for interest. The homeowner can deduct this from his or her taxable income. To the homeowner in the 40 percent tax bracket, every $100 in deductions translates into a $40 reduction in taxes paid to the federal or state government. During the first year, the benefits derived from the tax deductions for interest on the photovoltaic system for the buyer in the 40 percent tax bracket reduce the cost per kilowatt-hour produced by 30¢.

Tax considerations play a dominant role in determining the economic benefits of independent power. It is unfortunate that something as politically motivated and artificial should become a prime motivating factor. Remember that the same and even greater tax benefits are received by the utility companies and are a significant factor in determining the price they charge their customers.

Business tax benefits tend to be more favorable than residential tax benefits, because businesses can depreciate the equipment. That means they can deduct a portion of the cost of the facility every year. As will be explored in the next section, some homeowners are setting themselves up as corporations to take advantage of these benefits. It appears that this can be done only if all the electricity is sold to the utility rather than used internally.

Setting oneself up as a business is in keeping with Alvin Toffler's description of people becoming prosumers. In his best-selling book *The Third Wave,* Toffler describes homeowners who become producers as well as consumers. The person who buys a wind machine or a photovoltaic system should analyze such purchases differently than if he or she were buying a stereo or an automobile or refrigerator. The independent power system is an investment. The person who buys one should analyze its worth not only in psychological terms but in terms appropriate to any investment. Buying a wind machine is more akin to investing in a money market fund than to purchasing a refrigerator.

Opportunity Costs

Capital is a finite resource. The decision to invest in a power plant is really two decisions, one positive and the other negative. To invest in one project is not to invest in another. The benefits of one project must be compared to the lost opportunities of another investment. For example, $10,000 invested in a hydro project may generate a return of 10 percent on the investment after the loan and all other expenses are repaid. A similar investment in a corporate bond or money market fund may generate a 12 percent net return.

Investment in the money market fund (if the fund invests only in federally guaranteed securities) carries essentially no risk. Moreover, it is what economists call a *liquid investment*. It can be converted into cash at any time; checks may often be written on it even as the money is earning a risk-free return.

A small power plant carries a higher risk. Moreover, capital tied up in it cannot easily be converted to cash. Therefore, an investor may demand a higher return for this project than for a risk-free investment. When interest rates in federal securities were more than 15 percent in 1981, many investors were demanding a 25 percent return for investments in small power plants. In other words, they wanted their original investment repaid in less than four years.

The return the investor desires is called the *discount rate*. The discount rate is based on the inflation rate and the opportunity cost of money. Sometimes the term *real discount rate* is used. That is the discount rate after inflation has been taken into account. A real discount rate of 5 percent means the investor wants a return that is 5 percent greater than the inflation rate over the term of the investment.

To compare investment opportunities, one must take into account a wide variety of factors. For example, a money market fund invests in short-term securities. Thus the interest rate given to its investors fluctuates over brief periods. One may invest in the fund when interest rates are 15 percent but within a year they could drop to 10 percent or lower, as they did in late 1982. A small power plant investment is a long-term one. If one expects energy prices to rise faster than the general rate of inflation and if the buyback rate is based largely on the price of energy, then one might be justified in expecting to receive higher and higher returns in the future. Therefore, the slightly lower return at present might be justified on the basis of possibly very high returns in the future.

In making comparisons, one must be careful not to compare apples and oranges. The interest earned on a certificate of deposit at a bank or interest from a money market fund is taxable. If one is in the 40 percent marginal federal income tax bracket, the 12 percent return shrinks to 7.2 percent. Revenue gained from selling electricity to the utility is also taxable. But businesses are usually taxed at a lower rate than individuals. Moreover, the independent producer may be using some of the electricity on-site. The electricity not purchased from the utility is nontaxable income. If the utility charges 7¢ per kwh and the hydro plant displaces 1,000 kwh a month, the $70 normally paid to the utility is nontaxable income. (Put another way, if you are in the 30 percent tax bracket, the utility must pay you 30 percent more for your electricity than it charges you for its own before it makes it worth your while to sell it rather than consume it on-site.)

Investment decisions should also account for the *time value* of money. A dollar received a year from now is worth less than a dollar received today. At an annual inflation rate of 10 percent, a dollar received today and spent a year from now will have the purchasing power of only 91¢. Remember the misleading barrage of bank advertisements after the Individual Retirement Accounts (IRA) were established in 1981? They promised to make customers "millionaires" if they invested the maximum $2,000 each year for 30 years. The ads painted a picture that was more rosy than accurate, because they ignored the time value of money, that is, the reduction in purchasing power that inflation wreaks. True, anyone following the bank's advice would have a million dollars by retirement age. But a million dollars in the year 2015 would buy considerably less than it would have in 1981.

The loaf of bread in 2015 might cost $2.50. The average annual wage might be $50,000.

A more accurate analysis of the value of an IRA account would have taken inflation into consideration. Since long-term interest rates tend to be 2 to 3 percent higher than the long-term inflation rate, the actual rise in purchasing power for the investor would be 2 to 3 percent compounded over 30 years—significant but not sufficient to make the investor a 1981 millionaire.

The time value of money is taken into account by discounting each year's costs and benefits back to the present. Assume, for example, that the power-plant owner pays out an equal yearly loan payment of $3,000 for each of the first 10 years. What happens to the present value of that $3,000 for different inflation rates and for different time periods? Compare two cases (see table 7–1), one with a 15 percent inflation rate and the other with a 10 percent inflation rate. The table gives the present value of the $3,000 at the end of each year.

This comparison illustrates several points. Using a 15 percent inflation rate, $3,000 spent in the fifth year is worth only about $1,500 in present dollars. By the tenth year, the present value of the $3,000 has fallen to $742. In other words, an economic evaluation of this project takes into account that a revenue of $675 spent in the first year is equivalent to $3,000 spent in the tenth year. Note the dramatic difference in the present value of $3,000 based on the inflation rate

TABLE 7–1
The Time Value of $3,000

YEAR	ANNUAL INFLATION RATE OF 15%	ANNUAL INFLATION RATE OF 10%
1	$2,609	$2,727
2	2,268	2,479
3	1,973	2,254
4	1,715	2,049
5	1,492	1,863
6	1,297	1,693
7	1,128	1,539
8	981	1,400
9	853	1,272
10	742	1,157
Total	$15,058	$18,433

chosen, especially in the later years. Using a 10 percent inflation rate, the total present value of a stream of annual payments of $3,000 is $18,433. Discounting by 15 percent decreases the present value by 20 percent, to $15,058.

To compare costs and benefits properly, the revenue side of the equation should also be discounted. Thus, rising buyback rates should be discounted by some factor to be equated to the expenditures. With the assistance of a $15 pocket calculator and financial tables available in many economics and business textbooks, discounted cash flows can be developed.

The process of discounting for the time value of money is used not only to analyze the costs and benefits of small power plants but also to establish buyback rates. In many public service commission proceedings, the central dispute concerns the choice of the discount rate and its application to future plant construction costs or energy prices. The capacity credit portion of the buyback rate is the present value of avoided investments in future power plants. The capacity credit will be low if the cost of future power plants is low or if the discount rate is high. Since utilities want to minimize the capacity credit, they push back investment schedules, minimize the cost of future power plants and use a very high discount rate. As the above example illustrates, using a 15 percent rather than a 10 percent discount rate may lower the buyback rate offered QFs by 20 percent.

Utilities have other techniques to minimize PURPA rates. For example, construction cost increases for power plants have for the past decade been outrunning inflation. Therefore, the further into the future the construction takes place, the greater its present value. But many utilities ignore the historical data. They presume future construction cost increases will be below the inflation rate. This reduces the present value and reduces the buyback rates. Many arguments before public service commissions are about the choice of the discount rate used to deflate future dollars. Should it be the present rate of return the utility is permitted? The present rate of return is based on the interest paid on corporate bonds plus the return necessary to attract equity investors. This in turn is based on the inflation rate and long-term interest rates. Should the discount rate be based on the long-term interest rate or the short-term rate as illustrated in the rate of return? The difference in 1982 might be between 12 and 18 percent, making a dramatic difference in the present worth of investments ten years into the future.

When the time value of money is taken into account, benefits received in early years become disproportionately important compared to those received in later years. For example, $1,000 of tax credits that can be taken in the first year of operation may outweigh

$2,000 in revenue generated from rising buyback rates in the tenth year of operation.

Case Study: Wind Power

The economics of a specific wind-machine investment will be analyzed in some detail. Afterward, examples of hydropower, photovoltaic and cogeneration facilities will be examined in a more cursory fashion. The wind machine is a 10-kw machine rated to deliver 10 kw at 24-miles-per-hour (MPH) wind speed.

Costs can be divided between fixed costs and variable costs. Variable costs include insurance, taxes, metering fees and operation and maintenance (O&M). Assuming a simultaneous purchase and sales arrangement, metering costs are estimated to run $300 per year. O&M expenses are estimated to be 1 percent of the project costs or about

TABLE 7–2

Capital Costs of a 10-kw-Rated Wind Generator

Wind turbine	$8,172
65-foot tower	3,480
Excavation and foundation labor	1,668
Field materials (concrete, electrical and so forth)	1,968
Field installation labor	372
Equipment rental	216
Transportation	420
Taxes (6% sales tax on materials)	817
Fees, permits and inspections	120
Contractor overhead and profit	2,352
Interconnection costs	3,500
Total	$23,085

SOURCE: These estimates are based on those developed by Arthur D. Little in 1980. See William C. Osborn and William T. Downey, *Near-Term High Potential Counties for SWECS*, p. 86. Insurance and interconnection costs were added. Costs were inflated by 20 percent to account for inflation between 1980 and 1982.

$230 per year. An exemption from property taxes is assumed. Insurance premiums cost $200 a year. Thus the recurring costs amount to $730 a year.

Project costs should also include the costs of negotiating the PURPA contract, the cost of obtaining Federal Energy Regulatory Commission (FERC) certification as a QF, the cost of monitoring the wind and any other incidental expenses. These costs often add up to several thousand dollars and can occur many months, or even years, before the project generates any revenue.

If this machine is rated at a 24-MPH wind speed and operates in a 12-MPH average wind-speed regime, it will have a capacity factor of 20 percent. Thus it would have an annual output of 17,520 kwh per year (8,760 × 10 kw × 0.20).

An accurate evaluation takes into account tax credits, the interest rate on the loan to finance the system, the timing of future energy price increases and the timing of the output of the wind machine. Then a cash flow is developed for each year of the project. From this data one can estimate the return on investment.

Assume, for example, that the system cost of $23,085 is financed by a ten-year, 15 percent loan. Assume further that 80 percent financing is available for the long-term loan. The owner puts up 20 percent of the installation cost in cash.

The first year, the project generates revenue based on the estimated 17,520 kwh annual output, depending on how long it takes to install the wind machine. A more accurate cash flow examination would take into account the two- to four-month delay between the time the financing is taken out and the time the machine actually begins to generate power. The down payment for the long-term loan comes to about $4,600. Annual payments on the remaining $18,500 loan come to about $3,600. The first year interest is $2,700, which is of course deductible, in addition to maintenance expenses of $730 per year, also deductible. (The interest deduction will be less for each succeeding year.)

The second year of the project has the same expenditures as the first except for the down payment. This is also true for the remaining years of the project.

Tax Benefits

One further step remains to evaluate the economics of this project. Tax incentives must be included. Tax incentives for small-scale power production are available for residential and commercial enterprises. Different levels of benefits are available for different technologies and for business and residential systems.

Tax deductions are distinct from tax credits. The former is taken against gross income, while the latter is taken against tax liability. This makes the latter much more attractive. For example, suppose the individual homeowner is in the 35 percent tax bracket (combined federal and state taxes). A $1,000 tax deduction reduces gross taxable income by $1,000. This reduces tax liability by $350. The benefit of tax deductions is directly related to the tax level of the individual. If this homeowner were in the 50 percent tax bracket, the deduction would be worth $500. If his or her tax bracket were 15 percent, the deduction would be worth only $150. Tax deductions are useful only if one itemizes deductions on the income-tax form.

Tax credits are taken directly against tax liability. A $1,000 tax credit reduces taxes by $1,000. They can be taken even if one does not itemize deductions.

Both deductions and credits can usually be carried forward (and sometimes can be carried backward). Thus if one pays no taxes this year, but paid taxes last year or will pay them next year, the tax benefits can be applied in those years.

Small power plants are eligible for four types of tax benefits: investment tax credit, energy tax credit, depreciation and interest deductions.

The investment tax credit (available only to businesses) of 10 percent can be used by all businesses to offset investments in machinery. It is not restricted to investments in energy-related technologies.

Energy tax credits are available for all electric generation technologies covered in this book. Cogenerators are eligible, however, only if they are predominantly fueled by a renewable resource such as methane, solid waste or solar energy. Energy tax credits are available for residences as well as businesses. The level of the tax credit for businesses varies by technologies. Photovoltaic or wind technologies qualify for a 15 percent tax credit. Hydroelectric plants receive an 11 percent credit. Until 1982 there was a 10 percent tax credit for cogeneration plants, but this is available now only for those fueled by renewable resources such as methane or solid waste. There is no credit for cogeneration plants for residences. The residential tax credit for solar and wind is 40 percent at the federal level on a maximum investment of $10,000 ($4,000 maximum credit). Business tax credits have no ceilings.

One can deduct the depreciation of the equipment used in a small power system. This deduction is allowed under the presumption that the business is setting aside money to finance a new machine. The 1982 tax law renamed depreciation *accelerated cost recovery system* (ACRS). Depreciation is unavailable for residential ownership. However, it is available for technologies located on residential property but owned and operated by a commercial enterprise, which a homeowner could conceivably become. The 1982 tax law requires the power plant owner to reduce the basis for depreciation by 50 percent of the energy and investment tax credits. Thus if the equipment costs $100,000 and qualifies for 25 percent combined tax credits, the depreciation can be taken against a total equipment cost of $87,500.

The interest paid on a loan can be deducted. Given the time value of money, this provides an incentive to pay the interest up front. If one is in the 30-percent tax bracket, then 30¢ on the dollar paid to interest is actually being paid by Uncle Sam or the state or local government.

Many states provide additional tax benefits. Sometimes these can be used in addition to the regular federal tax credits, sometimes they are not additive. Kansas, for example, has a 30 percent tax credit for wind-electric machines that is taken in addition to the 40 percent federal income tax credit. California provides a state tax credit for the cost of any wind electric system that exceeds $12,000 and is not installed on a residential premise. This credit has no limit and is not reduced by any federal tax credits taken. Those who install a wind electric system that costs less than $12,000 or that is installed on residential premises are eligible for a 55 percent tax credit for the system's cost. This credit has a limit of $3,000 and is reduced by the federal residential tax credit. California taxpayers can also depreciate the entire cost of a wind electric system in one, three or five years instead of taking the state tax credit, or they can take the state credit and depreciate all costs in excess of the credit in three years.

Continuing with the wind machine example, the residential owner is eligible for the 40 percent federal tax credit on a maximum investment of $10,000. This provides a direct credit against taxes of $4,000. If the resident is in the 30 percent tax bracket, $3,430 in deductible expenses (first year interest of $2,700 and operating expenses of $730) equals $1,029 in reduced taxes, bringing the total first year tax reduction to $5,029. The energy tax credit is a one-time benefit. The interest deductions continue for the life of the loan.

The first year there is an outflow of about $9,100, generating a tax benefit of about $550 plus the tax credit of 40 percent of the first $10,000, or $4,000 for a total of $4,550. The second year the expenditure is $4,500 in loan payments. The tax benefit is $550 for a net expenditure of $3,900. That remains true for the remainder of the loan. If we rearrange these costs into net expenditures, the ten years give the following: the first year is $4,600, while subsequent years are $3,900 each for a total of $39,700 for ten years. Over the ten years the system will generate 175,200 kwh for a kwh cost of 22.7¢ ($39,700 ÷ 175,200 kwh).

Sensitivity Analysis

Any economic analysis should change key variables to examine how the results could vary. Then the most likely combination of variables should be chosen for the final analysis, with a likely range of values included in the final analysis as well. This is called a *sensitivity analysis*.

The situation painted above may actually be considered a worst-case scenario. It assumes a modest wind regime, a very short system life, a residential application with a ceiling on the tax credits, relatively high interest rates and no equipment salvage value. A worst-case scenario is an important antidote to Pollyannaish optimism. But a more realistic assessment of the project's economics would alter key variables.

One of the key variables here is wind speed. If the site had a 14-MPH rather than a 12-MPH wind speed, the annual electrical output would increase to 24,528 kwh. The kilowatt-hour cost over the ten-year period drops to 14¢.

This evaluation used an extremely short life expectancy for the wind machine. A more likely time period would be 20 years. Assuming a 12-MPH mean wind speed, the system will generate 350,400 kwh over 20 years. The additional 10 years will mean additional recurring costs (for maintenance) of \$7,300 (10 × \$730), raising total expenditures to roughly \$50,000. The cost per kilowatt-hour is then about 14¢.

The system will also be eligible for state tax credits, depending on its location. New York and California have a 55 percent tax credit for wind machines. This credit will lower the system cost by about \$2,300, reducing the cost of electricity by 2¢ per kilowatt-hour (in a 12-MPH wind regime).

Will the machine have any resale or salvage value? If a resale value of \$2,000 can be expected in 20 years, the cost of electricity is lowered again by about 2¢ per kilowatt-hour. A similar reduction would occur if the O&M costs dropped by \$100 a year over the life of the system, or if the metering costs dropped by a like amount.

If the wind machine has a built-in synchronous inverter and is located very near the utility line, the interconnection costs could drop by \$2,500 to \$3,000. This reduces the cost per kilowatt-hour by an additional 2¢ to 3¢.

Assuming all the most favorable factors, a wind machine operating for 20 years in a 12-MPH wind regime in California or New York would generate electricity at a cost of about 6¢ per kilowatt-hour. Assuming that interest rates for loans will also drop so that the original loan can be refinanced at a lower rate, the figure will drop still further.

This ends the examination of the expenditure part of the equation.

The key to the profitability of the project is the buyback rate. Today, buyback rates vary from less than 2¢ to about 9¢ per kilowatt-hour. In this example, assuming a 20-year system life, the total revenue will range from $7,000 to $31,500. Only under the most optimistic expenditure assumptions would the high end of this range of buyback rates generate a net profit for the project. However, the wind machine owner expects electric prices to rise, a rise that should be accompanied by an increase in the buyback rate. The profit of many of these projects is based on the expectation of future rises in avoided costs to the utility. For example, if the initial buyback rate is 5¢ per kilowatt-hour but escalates at an annual rate of 10 percent, the total revenue received over the 20-year period jumps from $17,500 to $50,000. By the twentieth year, the wind machine owner will be receiving 34¢ per kilowatt-hour. Figure 7–1 shows the relationship of energy inflation rates to the constant cost of the output of the wind machine.

The wind machine owner may be using all or most of the electricity on-site, or may have a net billing arrangement with the utility that reverses the meter. In that case, there may be no metering charges and few or no interconnection charges, and the price the producer receives for the electricity is the retail price. In most parts of the country, despite

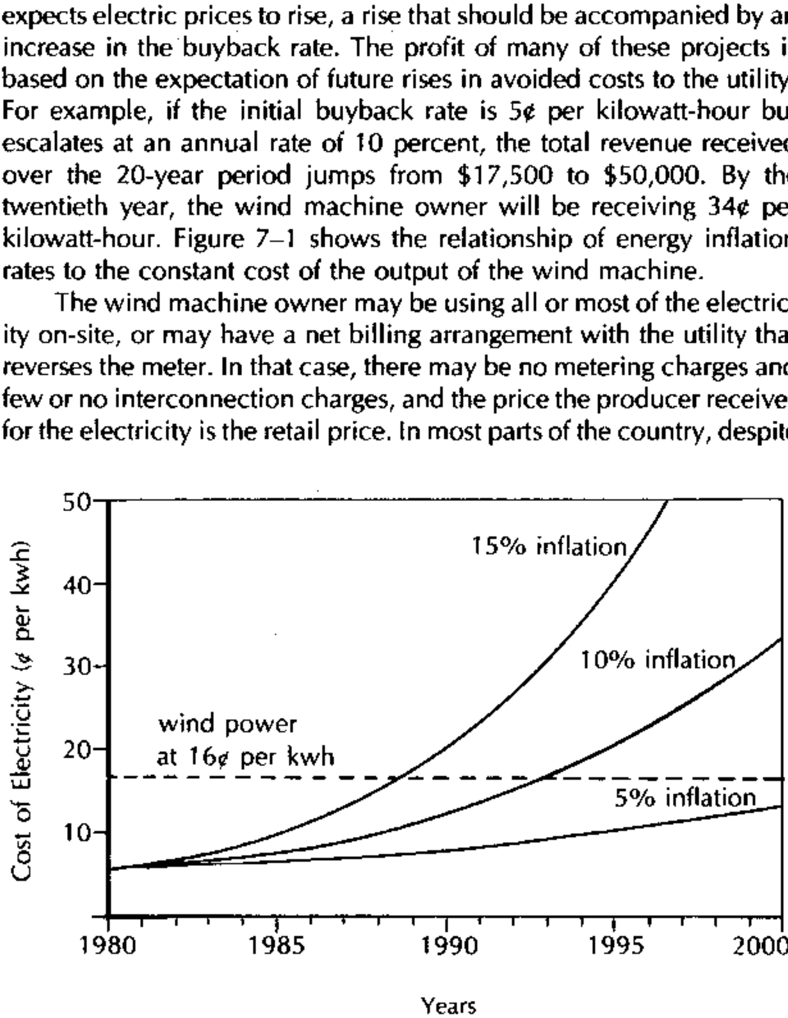

Figure 7–1: This figure shows a comparison of wind electricity and utility costs. The cost of the wind power assumed a $5,000 fee for purchase and installation, in addition to insurance and maintenance costs of $200 a year during a lifetime of 20 years. *Adapted by permission of Cheshire Books from* The Wind Power Book *© 1981 by Jack Park.*

PURPA's emphasis on marginal costs, utilities are paying less than their retail rate to QFs. Thus the wind machine owner will be generating a greater profit by consuming on-site. If this is the case, it also pays the wind machine owner to size the machine to use all of its consumption on-site. If the buyback rate is higher than the retail rate by more than the marginal tax bracket of the producer, then it encourages the sizing of the wind machine to extract a maximum amount of energy from that site.

The economics of the project change if they are examined as a commercial enterprise. Commercial projects qualify for investment and energy tax credits and accelerated cost recovery tax deductions besides the deductions for interest. Corporations often pay taxes in the 40 percent bracket. The machine may be owned by a group of investors called a *limited partnership.* In that case, the investors can take the tax benefits directly on their individual income tax returns. Limited partnerships are called tax shelters because they are a way to avoid paying taxes on income generated from some other enterprise or personal wages. The investors in these shelters are usually in the 50 percent tax bracket (higher if state taxes are taken into account). Thus deductions are worth much more to them than to the homeowner in the 30 percent tax bracket. From the previous wind system example assume a combined energy and investment tax credit of 25 percent (on the noninterconnection costs), a 40 percent business marginal state and federal income tax and a five-year ACRS. The first-year cash outflow of $8,930 (down payment of $4,600, mortgage payments of $3,600, operating expenses of $730) is nearly offset by the applicable tax benefits. Deductions of $6,480 (interest of $2,720, depreciation of $3,030, operating expenses of $730) generate $2,592 of tax benefits at the 40 percent marginal tax rate. This amount coupled with the allowable tax credit of $5,771 ($23,085 × 0.25) results in a total first-year tax benefit of $8,362, which almost entirely offsets the first-year cash outlay. Of course, the tax benefits decline in each ensuing year as a greater portion of each year's loan payments goes toward the principal.

The total expenditures over the 10-year loan repayment are $26,650. Assuming a 10-year life for the system, the cost per kilowatt-hour would be 15¢. Assuming a 20-year life, the cost would rise to about $33,000, but the kilowatt-hour cost drops to about 9¢. State tax credits, lower O&M costs and better loan terms or reduced interconnection costs would further lower this cost. Larger wind machines in windier regimes will be able to generate electricity at a much lower cost.

Ned Coffin, president of Enertech Corporation, a manufacturer of small wind systems based in Norwich, Vermont, describes in an article in *Alternative Sources of Energy* magazine the following situation where a Vermont resident purchased a 4-kw wind machine.[1] Instead of wiring the system to his house, he had the company wire it so that 100 percent of the output went to the utility.

The homeowner was going to create a subchapter S corporation. This type of corporation can be incorporated with little paperwork and allows the owner or owners to consolidate the income and losses of a business with their personal income, something that stockholders of regular corporations cannot do. Yet it still retains most of the other advantages of a true corporation, including a limited liability for the owners. In a subchapter S corporation, the owner can take a tax benefit granted to the business directly on his or her personal income tax.

The system cost $16,000. The enterprising Vermonter qualified for an immediate 10 percent federal investment tax credit and a 15 percent wind energy tax credit. In addition, the business qualified for an immediate Vermont business tax credit of $3,000. Moreover, the business can take off the first year's depreciation of 15 percent (even if the machine is purchased on December 31). On top of these tax breaks, the homeowner-owned corporation gets the income from the utility purchases of electricity (less the taxes paid on this earned income).

Tables 7–3 and 7–4 indicate the cash flow and the payback periods for the investment. Notice that the owner in the 50 percent tax bracket repays the initial investment in 5 years, whereas someone in a more typical 30 percent bracket would have a 6.5-year payback.

Coffin notes that his customer planned to abandon the corporation and to rewire the system to meet his household requirements once the system had paid for itself and all depreciation allowances had been used up. He estimated that at that time he would be getting a much higher return by using electricity internally than by selling it to the utility company and paying income tax on the proceeds.

Assuming a 10 percent annual increase in buyback rates and an owner in the 50 percent tax bracket, the initial investment of $16,000 will be recouped in about five years. In other words, the owner is getting about 20 percent return after taxes. If the owner is in a lower tax bracket, the payback period is slightly longer.

This example assumes an initial investment of $16,000; however, that investment need not mean a $16,000 up-front cash outlay. For example, the owner might pay $4,000 down and borrow the remaining $12,000. The tax credits can still be taken against the full $16,000 and the depreciation can be taken on $14,000. Thus, by putting a cash down payment of $4,000 plus paying the debt service on the remaining $12,000, the independent power producer can generate $8,410 in income and tax benefits the first year. Assuming all the tax benefits can

TABLE 7–3

Cash Recovery

		CUMULATIVE DOLLARS RETURNED
Initial Investment—$16,000		
Federal Energy and Investment Tax Credits (25%)	$4,000.00	
Immediate Vermont Business Tax Credit ($3,000 max)	3,000.00	
1st year depreciation (15% × $14,000 × 50% tax bracket)	1,050.00	
1st year income (9,200 kwh @ $0.078 less 50% taxes)	360.00	
Total 1st year cash recovery	$8,410.00	$ 8,410.00 (52.6%)
2d year depreciation (22% × $14,000 × 50% tax bracket)	$1,540.00	
2d year income (9,200 kwh @ $0.086 less 50% taxes)	395.00	
Total 2d year cash recovery	$1,935.00	$10,345.00 (64.7%)
3d year depreciation (21% × $14,000 × 50% tax bracket)	$1,470.00	
3d year income (9,200 kwh @ $0.094 less 50% taxes)	430.00	
Total 3d year cash recovery	$1,900.00	$12,245.00 (76.5%)
4th year depreciation (21% × $14,000 × 50% tax bracket)	$1,470.00	
4th year income (9,200 kwh @ $0.104 less 50% taxes)	480.00	
Total 4th year cash recovery	$1,950.00	$14,194.00 (88.7%)
5th year depreciation (21% × $14,000 × 50% tax bracket)	$1,470.00	
5th year income (9,200 kwh @ $0.114 less 50% taxes)	525.00	
Total 5th year cash recovery	$1,995.00	$16,190.00 (101.2%)

NOTE: Reprinted from *Alternative Sources of Energy* magazine, issue 59. For subscription information, write to them at 107 S. Central Ave., Milaca MN 56353.

TABLE 7–4

Cash Recovery Calculations

(Wired to Utility, then House, vs Wired to House)

I. ASSUMPTIONS	WIRED TO UTILITY	WIRED TO HOUSE
Installed Cost	$16,000	$16,000
Federal Tax Credits	$ 4,000	$ 4,000
State Tax Credits	$ 3,000	$ 1,000
Net Cost after Tax Credits	$ 9,000	$11,000
Depreciation *	$14,000	-0-
Output (kwh)	9,200	9,200
Price/kw	$ .078	$ .078
1st Year's Earnings/Savings	$ 718	$ 718
Annual Rate Increase	10%	10%

	OWNER'S TAX BRACKET		
II. WIRED TO UTILITY, THEN HOUSE	50%	40%	30%
Net Cost after Tax Credits	$9,000	$9,000	$9,000
Taxes Saved by Depreciation	$7,000	$5,600	$4,200
Net Cost to Owner	$2,000	$3,400	$4,800
1st Year's Earnings, Less Taxes	(359)	(431)	(503)
5 Years' Earnings, Less Taxes–Assuming 10% Annual Rate Increase	$2,190	$2,630	$3,068
Balance Remaining, 5th Year	-0-	$ 770	$1,732
6th Year's Cash Savings–Assuming 10% Annual Rate Increase †	$1,149	$1,149	$1,149
Years to Cash Recovery	5	5.5	6.5
III. WIRED TO HOUSE			
Net Cost after Tax Credits	$11,000	$11,000	$11,000
1st Year's Cash Savings †	(718)	(718)	(718)
5 Years' Earnings–Assuming 10% Annual Rate Increase †	$ 4,380	$ 4,380	$ 4,380
Balance Remaining, 5th Year	$ 6,620	$ 6,620	$ 6,620
6th Year's Cash Savings–Assuming 10% Annual Rate Increase †	$ 1,149	$ 1,149	$ 1,149
Years to Cash Recovery	10	10	10

NOTE: Reprinted from *Alternative Sources of Energy* magazine, issue 59. For subscription information, write to them at 107 S. Central Ave., Milaca MN 56353.

* Can be used to offset taxes on corresponding amount of income from other sources.

† Cash savings only are shown. For persons to whom $1,000 saved is equal to $1,500–$2,000 earned, the value of these savings is obviously higher.

be used in that year (or carried forward to be used in later years), the return on cash outlay is more than 100 percent the very first year.

In my opinion, the next steps in the economic evaluation for both business and residence are to develop a 20-year cash flow and to discount the various benefit and expenditure streams to their present value. This weights the evaluation to favor those benefits received early (e.g., tax credits) versus those received later (e.g., rising buyback rates). Earlier it was noted that at a 10 percent escalation rate, a 5¢-per-kilowatt-hour buyback rate in 1983 becomes a 34¢-per-kilowatt rate in 2003. But we must also discount that back to the present, reducing its value to current investors considerably. This is why investors will often sign contracts with utilities that give them higher than normal buyback rates immediately, possibly 125 to 150 percent of the regular rate, and then reduce that rate over the next few years so that in later years they are receiving less than the regular rate. The discounted benefits are then compared to the discounted costs and an internal rate of return is computed. If the return is equal to or greater than that desired by the investor, the project is attractive.

As the reader can see, an examination of any project is complete with arithmetic exercises, hard work and educated guesses about the future. The reward is that the prospective power plant owner will have a much clearer idea of the range of possible outcomes of the project and its value.

Hydropower

Construction-cost estimates for hydropower systems may be subject to more variation than estimates for wind-power systems. Part of the reason is that regulatory delays can increase construction costs through inflation. Another is that regulations can impose conditions on flow rates and require fish ladders or certain engineering designs that increase the project's costs. The costs for hydroelectric facilities will vary significantly depending on whether there is an existing dam, whether used equipment is installed, how far the power plant is from the utility and the cost of interconnection equipment. For this example, assume a sufficient flow rate and head to support a 50-kw plant. The installation cost, including switch gear and interconnection equipment, is assumed to be $3,000 per kilowatt for a total cost of $150,000. The facility is assumed to operate at a 60 percent capacity factor, typical of facilities lacking storage ponds. At a 60 percent capacity factor, this plant will generate 262,800 kwh annually.

Hydro facilities last more than 40 years. Here assume a 25-year life in which the system will generate 6.5 million kwh. Assuming its $150,000 installation cost is financed at 15 percent over 10 years, the total principal and interest paid out is slightly more than $290,000. Assuming operation and maintenance expenses of 1 percent of the system's cost and insurance of $1,000 per year, the total expenditures over 25 years come to about $350,000. The cost per kilowatt-hour generated is 5.4¢. Interest deductions and tax credits will lower this figure to 2¢. The reader can understand why prospectors searched the nation in the early 1980s looking for viable hydro sites with existing dams.

Cogenerators

An economic analysis of cogeneration plants is more complicated because one must take into account rising fuel prices as well as the other cost components. For this analysis a Re-Energy system is used. The system uses a 140-horsepower (HP) Mack Truck engine operated at 70 HP. The engine drives a 50-kw generator. The system is designed to operate 100 percent of the time to meet the base load. Under full load the system converts about 38 percent of its energy burned into electricity. An additional 58 percent of the primary energy is recovered as useful thermal energy.

The installed cost of the system is $80,000. Assuming a 12 percent, five-year loan on the system, the yearly payments are $21,143.

For every one million Btu of primary energy burned in the Re-Energy system, 380,000 Btu of electric power are generated, or 111 kwh and 580,000 Btu of useful thermal energy are recovered. Using a 1983 average national cost of natural gas of $7 per million Btu (70¢ per therm), the cost of generating a kilowatt-hour of electricity is 6.31¢ if we assumed no heat were recovered. Given that the efficiency of the heat recovery compares favorably with the efficiency of a commercial boiler (although it is about 10 to 15 percent lower than the efficiency of a well-tuned residential furnace), one could be justified in viewing the electrical output as having no additional cost. The inherent economics of a cogeneration system is that it provides two products for the price of one. And one of those products—electricity—has a very high value to the user. Seven cents per kilowatt-hour, the typical cost of electricity, translates into more than $20 per million Btu, nearly three times the cost of natural gas or fuel oil.

If this system were run 100 percent of the time, it would produce 50 kw × 8,760 hours = 438,000 kwh per year plus 2.3 billion Btu of thermal energy.

We can now estimate the payback. If all the electricity were used internally and displaced 7¢ per kilowatt-hour, the return would be $30,660. Thus the net operating profit on the system is $9,000. (The company provides a warranty for the system for five years and takes care of all maintenance, including oil changes and valve adjustments.)

With tax benefits added in, the return is even more attractive. The residential owner receives no tax benefits. Given the scale of even the smallest cost-effective cogeneration systems and the fact that tax benefits are available only to commercial enterprises, these systems will be predominantly installed in commercial structures or under a corporate umbrella for an association of homeowners or apartment house dwellers.

The 10 percent investment tax credit and 10 percent credit for cogeneration (which expires in 1983 but may be extended by Congress) gives a first-year tax credit of $16,000. The depreciation in the first year is 15 percent. Assuming a 40 percent tax bracket for the business, this is equivalent to a 6 percent tax credit. Thus the business gets more than $20,000 in tax benefits the first year as well as the $9,000 net income from the electricity.

In this case assume equal efficiencies for the cogeneration system and the commercial boiler. Therefore, the natural gas consumed would have been consumed anyway for space heating and domestic hot water.

There are many variables to watch for when installing a cogeneration system. If the boiler were 80 percent efficient compared to the thermal energy recovery efficiency of 58 percent for the unit in the example, one would have to calculate in the additional natural gas burned to generate the electricity. If the system operated only 50 percent of the time, the operating cost for generating electricity would be 6.3¢ per kilowatt-hour. Thus the 7¢ displaced generates less than a penny return per kilowatt-hour.

This example assumed all electricity was used internally. This is one reason the system was sized to generate 50 kw. If the buyback rate of the utility were 7¢ or over, the owner would probably install a larger system (depending on the use to which the waste heat could be put) and export even more to the utility. But in most parts of the country, the buyback rate will only be a fraction of the rates the utility charges the customer. If the buyback rate were 5¢ per kilowatt-hour and the system operated 100 percent of the time, the operating profit would drop to about $6,500.

The comparative cost of the fuel used for the cogeneration system and for the central power plant is an extremely important variable. This example assumed a cost of $7 per million Btu for natural gas. If the utility is meeting increased demand and has oil-fired capacity, the buyback rate should be 5¢ to 7¢ per kilowatt-hour. The lower the cost of natural gas, the more attractive the cogeneration installation will be. If, on the other hand, gas prices are high and the utility is coal fired with no plans for any future capacity additions, the cogeneration system could not be economically justified on the basis of generating electricity for sale.

Cogeneration plants have an advantage that wind power and photovoltaics and, to a certain extent, hydropower do not have. They can and should qualify for capacity credits. They can meet any reliability standard utilities offer, and they can be operated so that maintenance takes place in the off-peak periods, allowing them to qualify for time-of-day energy credits. Thus cogeneration facilities should be able to qualify for the highest buyback rates offered. Capacity credits can add 1 to 2¢ per kilowatt-hour to the buyback rate.

However, capacity credits or firm energy credits usually require long-term contracts. If there is no escalator clause to the contract, the cogeneration plant fired by natural gas will be in a particularly difficult situation as gas prices continue to rise dramatically. If the local utility has peaking plants fired by oil, the rising gas prices will possibly increase the generation cost of electricity on-site more rapidly than avoided energy costs increase at the utility level. If the utility is switching to coal and nuclear plants and is retiring its oil- or gas-fired peaking plants, the situation could become worse for the independent power producer. If the natural gas price increases at a faster pace than do electric rates, the project will experience a loss in the later years.

Cogeneration systems can also be used as load-leveling devices. They can be turned on during peak periods of the day or year to reduce demand charges. Only commercial customers now pay demand charges. These can represent 50 percent of the total utility bill. In the case of peak-shaving or load-leveling uses, the cogeneration system need not be designed for long periods of use between maintenance. It can have a higher number of revolutions per minute (RPM) and will cost considerably less than the model used in this example.

Photovoltaics

A small household photovoltaic (PV) system can use the electricity generated to meet the household load, or it can sell it to the utility or store it in batteries or in hot water tanks. Whichever strategy is chosen will in large part be based on the buyback rate, the cost of storage and other factors.

The size of a residential system in the next few years will probably be influenced by the ceiling on the residential solar tax credit. The 40 percent federal tax credit can be taken only on the first $10,000. That price is currently sufficient to install a 1-peak-kilowatt system. In a typical location, that system will generate about 1,700 kwh annually. Since the typical American household consumes 7,500 kwh a year, one might be tempted to assume that the entire output could easily be used on-site. But remember, the electricity is not generated from the PV device at precisely the time it is needed by the internal load. Therefore, during parts of the year, the household will have to store, dump or export the surplus electricity. If the surplus coincides with the utility's air-conditioning peak, the PURPA buyback rates may be attractive. For a household system, the metering costs, back-up rates and interconnection charges become primary factors in encouraging or discouraging utility sales. Net billing arrangements where the household can use the original watt-hour meter are most attractive.

If the utility charges a high back-up rate (possible under an excess sales arrangement) or if its buyback rate is too low, the household owner may decide to store the electricity on-site. This can be done in batteries. But it can also be done by converting the electricity to hot water. Each 100 kwh of extra capacity per month is enough to raise the temperature of 20 gallons of water by about 70°F a day, enough to meet one person's hot water needs. The economic benefit derived from this depends on the cost of heating hot water ordinarily. The additional capital costs for the PV owner might consist of a transfer switch to direct the electricity to the storage tank when no load is present and possibly a larger water storage tank to prevent overheating of the water.

Assuming a system cost of $10,000, operation and maintenance costs of 1 percent or $100 per year and a 10-year, 15 percent loan, the total expenses over 20 years will be $21,000. Interest payments are about $9,400. The residential tax credit generates $4,000 in the first year of operation. (California and New York have 55 percent tax credits, lowering the price still further.) Assuming a 35 percent combined state and federal income tax bracket, the tax deductions reduce the expenditures by another $3,150, reducing total expenditures to $13,850. Since the system will generate 34,000 kwh over 20 years, the total cost per kilowatt-hour is slightly over 40¢.

This is too high for most people. But remember that the revenue for this household will come primarily from displacing utility-purchased electricity. The retail rate of electricity in some parts of the country is now 16¢ per kilowatt-hour and is increasing on average 10 to 15 percent a year. Meanwhile, the cost of PVs is declining. And there is the distinct possibility that cogeneration-PV systems will be developed. These will capture the thermal energy from the solar collectors as well as the electrical energy, increasing the revenue further. Imagine charting this on a graph. The two lines of reducing cost and increased retail price of electricity are expected to intersect in some parts of the nation by as early as 1985.

Obviously, a commercial PV system would be larger than one for a household. To evaluate such a system, assume a 20-kw peak array with an installed cost of $9,000 per peak kilowatt. The total loan is for $180,000. Assume a 10-year, 15 percent loan term. The cost for the first year will be $34,800, of which $26,400 is interest. Assuming operation and maintenance costs of 1 percent of system costs, the additional expenditures will be $1,800 a year. The total expenditures over the 20-year life of the system will come to $380,000. Total electricity generated over 20 years is 680,000 kwh. Total cost per kilowatt-hour generated in gross terms is thus 56¢.

The system is eligible for a 25 percent tax credit with no ceiling. It is also eligible for ACRS over five years. And the interest payments, as with the residential owner, are tax deductible. Assuming the facility is owned by a limited partnership with each of the partners in the 50 percent tax bracket, these tax benefits total $215,000. The cost per kilowatt-hour drops to 24¢. If the system is located in the higher insolation areas of the nation (e.g., the Southwest), the output from the 20-kw array could increase by 20 percent, reducing the cost per kilowatt-hour to less than 20¢.

In summary, an economic analysis is the single most important step *before* investing in small power production. This is the step in which all the data previously gathered is combined, where the cost data, the operational data, the PURPA rates, the internal-load-curve data and evidence of future buyback rates and financing terms are put together to provide a picture of the cash flow generated from the project. The economic analysis should project the cash flow, that is, the expenditures and revenues generated in each year, or each month, so that the owner will be able to identify those periods, especially during the early years, where more money will be going out than coming in. A sensitivity analysis can identify the factors that could substantially change the picture (e.g., changing reliability factors, future buyback rates and changing interest rates). The economic analysis should also provide several future scenarios, using a low, middle and high range for various factors and, if possible, applying a risk factor to each scenario.

Completing this task provides a good picture of what can go right, what can go wrong and what the venture looks like overall. Sometimes an economic analysis clearly cautions against investing. In most cases it defines the parameters or range of possible returns and the likelihood that the project will fall within that range. The decision to go or not is still an individual one. All the data and analysis in the world will not persuade an individual used to investing in federally guaranteed short-term securities suddenly to embark on a novel and risky venture. It does allow you to look before you leap.