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Strategic Planning in Electric Utilities: Using Wind Technologies as Risk Management Tools

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STRATEGIC PLANNING IN ELECTRIC UTILITIES: USING WIND TECHNOLOGIES AS RISK MANAGEMENT TOOLS

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ABSTRACT

This paper highlights research investigating the ownership of renewable energy technologies to mitigate risks faced by the electric utility industry. Renewable energy technology attributes of fuel costs, environmental costs, lead time, modularity, and investment reversibility are discussed. Incorporating some of these attributes into an economic evaluation is illustrated using a municipal utility's decision to invest in either wind generation or natural gas based generation. The research concludes that wind and other modular renewable energy technologies, such as photovoltaics, have the potential to provide decision makers with physical risk-management investments.

INTRODUCTION

Regulatory and technical forces are causing electric utilities to move from a natural monopoly to a more competitive environment. Associated with this movement is an increasing concern about how to manage the risks associated with the electric supply business. There are several approaches to managing these risks. One approach is to purchase financial instruments such as options and futures contracts (Ref. 1). Another approach is to own physical assets that have low risk attributes or characteristics (Refs. 2, 3).

This research investigates the potential of mitigating risk by owning renewable energy technologies. Explicit consideration is given to the attributes of fuel costs, environmental costs, lead time, modularity, and investment reversibility. Ownership perspectives include investor-owned utilities (IOUs), municipal utilities, independent power producers (IPPs), and power consumers. Analytical approaches include risk-adjusted discount rates within a dynamic discounted cash flow framework, option valuation, decision analysis, and future/forward contract comparisons. See Ref. 4 for complete study results.

The research concludes that renewable energy technologies, particularly the modular technologies such as wind and photovoltaics, have the potential to provide decision makers with physical risk-management investments.

RENEWABLE ENERGY ATTRIBUTES

Fuel Costs

One of the most often stated positive attributes of renewable technologies is that they have no fuel costs. As a result, there is no uncertainty associated with the future fuel costs to operate a renewable power plant. All ownership perspectives mentioned earlier can benefit from this attribute. Different ownership perspectives, however, will benefit to a different degree with those experiencing the most uncertainty realizing the greatest benefit. Currently, this includes IPPs and power consumers because fluctuations in fuel costs (or electricity prices) directly affect the profit of IPPs, the profit of commercial and industrial users of electricity, and the well-being of residential consumers who use power for their residential needs. IOUs and municipal utilities that generate power realize less benefit from a reduction in fuel cost variability because they currently pass this uncertainty on to customers through fuel adjustment clauses. In a more competitive environment, however, it is unlikely that this practice will continue.

When comparing renewable plants to fossil-based plants, the absence of fuel cost uncertainty must be added as a benefit of the renewable plant or counted as a cost of the fossil-based plant. Cost analysis for fossil-based plants typically projects a stream of expected fuel costs, discounts the results, and considers the present value cost as part of the cost of the plant. This analytical approach, however, improperly converts the uncertain stream of future fuel costs into a stream of certain costs without accounting for the reduced uncertainty.

One way to account for this uncertainty is to determine the premium charged for a fixed-price long-term fuel contract (e.g., a natural gas contract) over a series of spot-market based purchases (Ref. 5). Such a contract is analogous to a financial swap (i.e., a series of forward contracts). A second approach is based on utility theory and involves assessing the decision maker's utility function to determine his or her willingness to pay for "certainty" fuel instead of "risky" spot-market based fuel.

Environmental Costs

Another attraction of renewables is that they produce low or no environmental emissions. Quantifying the value of this benefit, however, is controversial. A good part of the debate stems from the fact that the various participants in the process may have vastly different valuations.

The perspective taken in this paper is that of the plant owner, including investors in IPPs, utilities, or power customers. Plant owners can incur two types of costs associated with emissions. First, there is the additional cost of building the plant to comply with current environmental standards. This cost, which is minimal when environmental standards are low, is usually included in evaluating all types of plants, both fossil-based and renewable.

Second, there is the cost associated with future environmental standards that have not yet been established. As Swezey and Wan point out, "prospective environmental cleanup costs of fossil-fuel-based plants are never considered up-front when generation investment decisions are made (Ref. 6)." These future costs have the potential to be quite high. Pacific Gas and Electric Company, for example, estimates that compliance with NO_x emissions rules for its existing power plants could require capital expenditures of up to $355 million over the next ten years (Ref. 7). It is likely that these costs were not anticipated by Pacific Gas and Electric Company when the plants were initially constructed. Power plants that are considered to be very clean by today's standards (e.g., natural gas based generation) may fare very poorly in five years.

A conceptual framework that can be used to view this future cost is that the decision to build any pollution generating source includes the plant owner's decision to give a valuable option to the government. The option gives the government the right (but not the obligation) to change emissions standards or impose externality costs (i.e., environmental taxes) associated with environmental damages at any time and require that all generators meet the standards. The result of this is that there is a positive probability that the plant owner will incur costs in the future. The cost of this option must be accounted for when comparing fossil-based to renewable plants. Either fossil-based plant owners require compensation for the option that is given to the government or renewable plant owners need to be given a credit. The benefit of low or zero future environmental costs depends on who owns the plant, because some owners are more likely to incur environmental costs. For example, utilities and IPPs are likely to experience more stringent regulation than power consumers who own plants.

Lead Time

Projects with short lead times tend to have greater certainty associated with their installed cost because of fewer cost overruns and less lost revenue caused by plant delays. This is of interest to any party that is responsible for plant construction, although it is most significant for IPPs because utilities and power consumers frequently install generation facilities through a contracting procedure, thus shifting the construction risk away from themselves to the contractor.

IOUs and municipal utilities are still considered to be regulated natural monopolies, which requires them to serve all customers regardless of whether or not it is profitable to do so. The interaction between demand uncertainty, plant lead time, and capacity additions is of concern to these utilities. The smaller the utility, the greater the concern. For this reason, municipal utilities might be particularly concerned about demand uncertainty at the generation system level.

A typical approach to assessing the interaction between demand uncertainty, plant lead time, and capacity additions is to develop scenarios of high, medium, and low demand (Ref. 8) and to calculate the expected present value cost of meeting demand using plants with different lead times.

This approach, however, does not capture the dynamic nature of demand growth. Demand growth can change over time so that demand can grow or not grow at each point in time. For example, rather than always having high, medium, or low demand growth, actual demand may be high the first year, low the second year, and medium the third year. This leads to the situation where the number of scenarios equals the possible growth rate at each time period raised to the power of the number of time periods. For example, if demand growth rate can take on three levels at any time and there are ten time periods, there is a total of 3^{10} or almost 60,000 possible scenarios.

Taking the dynamic nature of demand growth into account rather than simply examining three scenarios results in a valuation that more accurately captures the effect of demand uncertainty. This will often result in an increase in the value of plants with short lead times over the value of plants with longer lead times.

Modularity

Plant modularity affects plant availability in several ways. First, from a revenue perspective, modular plants begin producing power (and thus revenue for utilities and IPPs or cost-savings for power consumers) earlier than non-modular plants. Modular plants begin producing power earlier than non-modular plants because each segment of a modular plant can come on line as it is completed.

Second, from an operational perspective, modular plants have less variance in their equipment availability than non-modular plants when equipment failures in the modular plant are independently distributed. A non-modular plant can be considered to be either operating or not operating. Modular plants, by contrast, can have partial availability. For example, a modular plant with two identical segments has three possible levels of availability: the plant is 100% available if both segments are functional; it is 50% available if either the first or the second segment is functional; and it is unavailable if both segments are non-functional.

The greater the number of segments in the modular plant (i.e., the more modular the plant is) the lower the variance. This means that there is a greater reliability associated with the availability of modular plants than with non-modular plants. Wind and photovoltaic plants are modular and are composed of a large number of identical parts.

In addition, a modular plant ties up fewer capital resources during the construction of the total plant. The project developer needs only enough working capital to finance one segment at a time. Once the first segment is completed, it can be fully financed, and the proceeds used to finance the next segment. This benefit is of particular interest to companies with limited financial resources, such as IPPs.

This benefit is similar to the benefit realized by a developer that chooses to build single-family dwellings rather than an apartment building. The full financial resources are tied up in the apartment building before it is sold while the single family dwellings can be sold as they are completed, thus requiring less working capital.

Moreover, continued construction of a modular plant is often contingent on the success of the previous phase so that there is the opportunity to stop the project without incurring a total loss after each segment is completed. This is because the completed increments of the project are used to produce revenue whether or not the project is fully completed. The same is not true for non-modular projects. While there is always the opportunity to halt construction, doing this on a non-modular project results in a loss of all capital invested to date, less the partially completed project's salvage value. While modularity thus provides value to utilities who want to control demand uncertainty, it is also of value to investors who are funding an IPP and are unsatisfied with the project's progress.

For these reasons, utilities are investing in small plants, such as gas turbines. Even smaller investments may further increase the risk-mitigation value.

<u>Investment Reversibility</u>

Investment reversibility is the degree to which an investment is reversible once it is completed. This is of interest to plant owners because they need to know if a plant can be salvaged and what its value is in an alternative application. Modular plants are likely to have a higher salvage value than non-modular plants because it is more feasible to move modular plants to areas of higher value or even for use in other applications. The degree of reversibility is a function of the difficulty and cost in moving the technology to another location and the feasibility of using it in different applications.

This value is not merely a hypothetical one. Consider, for example, the case of the 6 MW Carrisa Plains PV plant facility (California). Its original owner (Arco Solar) sold the plant for strategic reasons to another company. This company dismantled the plant and resold the modules at a retail price of $4,000 to $5,000 per kilowatt at a time when new modules were selling for $6,500 to $7,000 per kW.

ILLUSTRATION OF PRINCIPLES

<u>Municipal Utility Purchases Wind Generation</u>

Municipal utilities represent an important market for wind technologies for several reasons. First, they are likely to continue investing in power plants as opposed to only purchasing power from other power producers. Second, they appear to be able to represent the preferences of their customers for renewable energy technologies in their purchase decisions. Third, they have a lower cost of capital, thus reducing some of the bias against generation technologies that have high initial capital costs and low operation and maintenance costs. Fourth, their tax-exempt status eliminates the tax benefit of expenses (e.g., fuel costs) over long-term capital costs.

This illustration compares the cost of a municipal utility's investment in wind generation with its cost of an investment in natural gas-based generation. The risk-mitigation benefits associated with the wind generation that are presented include the elimination of natural gas fuel price uncertainty, the elimination of potential future environmental costs associated with carbon emissions, and the value of more effectively matching generation system capacity with demand. The following discussion is meant for purposes of illustration and is not meant to imply that these are the only attributes of importance in this scenario.

Capacity and Demand

The municipal utility's historical and projected peak demand and its existing generation system capacity are presented in Figure 1. The current year is 1995 and the peak demand for this year is 480 MW. The lower solid line describes what historical peak demand has been from 1991 to 1995. The dashed lines describe projected peak demand with the light lines corresponding to the possible peak demands and the heavy line corresponding to the average peak demand. The utility has been experiencing an annual load growth of either 10 MW/year or 0 MW/year, each with an equal probability of 0.5. The utility believes that this same trend will continue in the future. The figure suggests that there will be no excess system capacity if peak demand increases for two consecutive years.

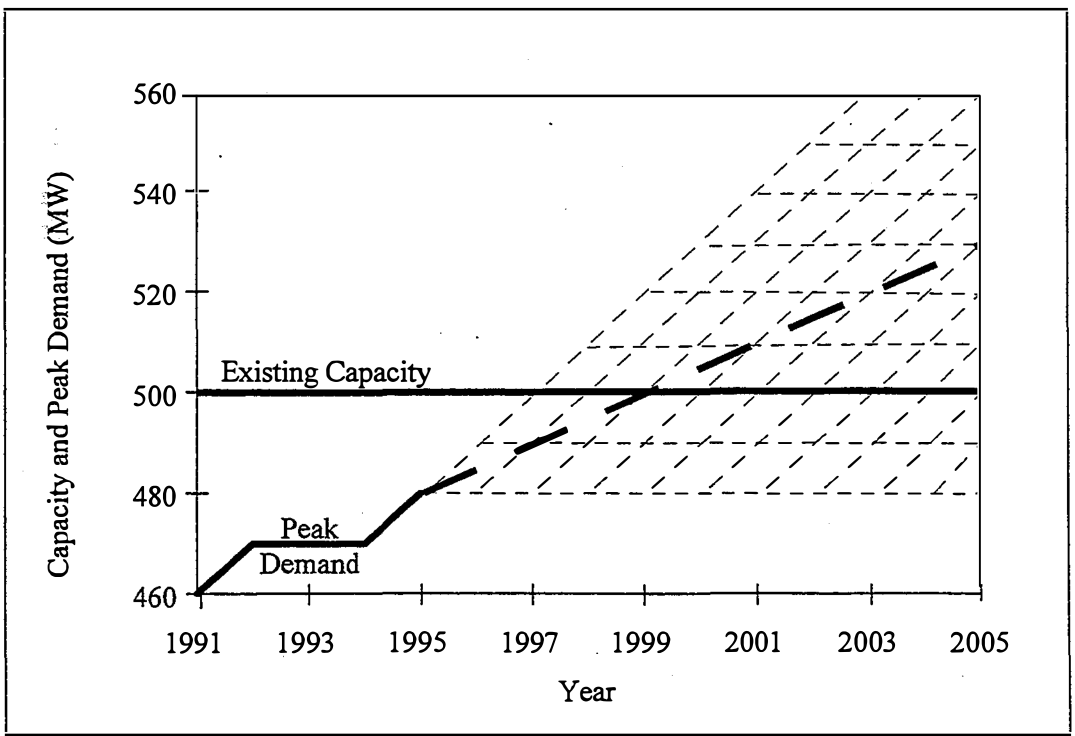

Figure 1. System capacity and peak demand.

Generation Alternatives

The utility has decided that it will either purchase a 50-MW natural gas-based plant or an equivalent amount of wind generation. It has completed a detailed, multi-year wind resource assessment program and has evaluated the match between the wind plant output and its peak load. Results indicate that a wind plant would have a 40% annual capacity factor (combined wind resource and equipment availability) and would provide generation system capacity equal to 40% of its nameplate capacity.

The natural gas-based plant can be operated at an 80% annual capacity factor for 20 years and has a 20% forced outage rate. Thus, a 100-MW wind plant is needed to provide the same generation capacity and the same amount of energy as the natural gas-based generation (i.e., a 50-MW natural gas-based plant with a 20% forced outage rate and 80% capacity factor increases system capacity by 40 MW and produces 350 GWh/year; a 100-MW wind plant increases system capacity by 40 MW and produces 350 GWh/year). Both alternatives will be fully financed by tax-free municipal bonds at 5%.

The plants differ in two major ways. First, the natural gas plant must be constructed all at one time, while the wind plant can be constructed in 25-MW segments so that each segment increases system capacity by 10 MW. Second, the natural gas plant has a 2-year lead time while each segment of the wind plant has a 1-year lead time.

Construction on the natural gas plant must begin immediately in 1995 so that the plant will be available if demand increases by 10 MW/year for two consecutive years. The top dashed line in Figure 2 presents system capacity with the natural gas-based generation.

In terms of the wind plant, the time at which each of the 25-MW wind plant segments must be built is uncertain. For example, construction on the first segment will begin when peak demand reaches 490 MW for the first time. This can happen in 1996 (0.5 probability), 1997 (0.25 probability), 1998 (0.125 probability), etc. The mathematical formulation of how to calculate the probability of demand reaching a certain point for the first time is fully developed in Reference 4. When this calculation is repeated for each of the four segments and the results summed, the expected increase in system capacity is as presented by the lower dashed capacity line in Figure 2.

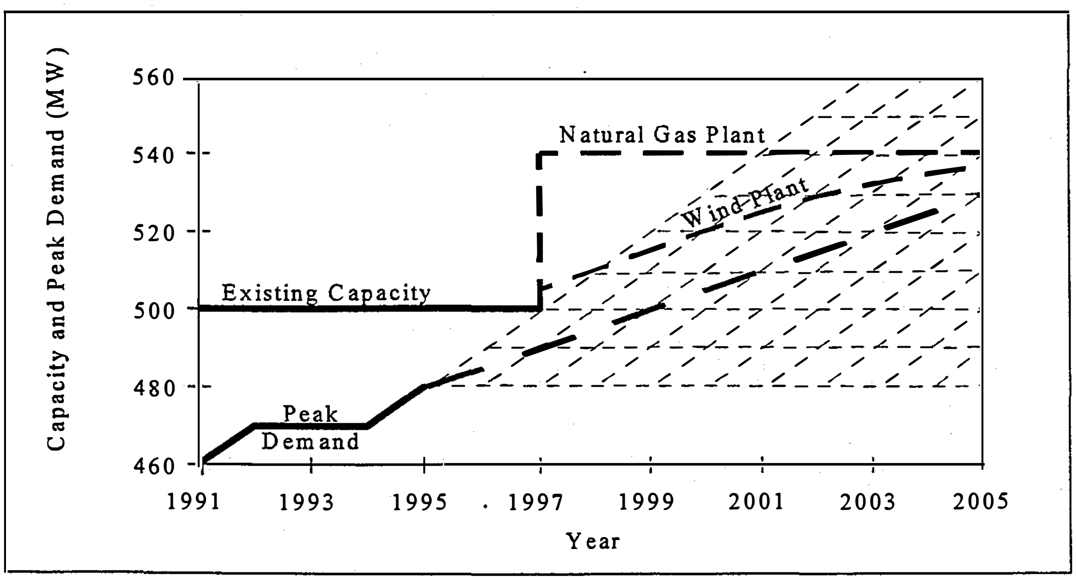

Figure 2. Capacity increases associated with gas and wind plants.

Wind Plant Costs

Two costs associated with the wind generation are its initial capital cost and its O&M cost; it is assumed that there are no firming costs and no added transmission costs. The wind plant capital cost is $800/kW and the O&M cost is $0.005/kWh. The annual O&M cost is $18/kW-year based on a 40% capacity factor. Using a discount rate of 5% (equal to the municipals cost of capital) for the 20 year life, the total present value cost equals $\$800+\sum_{i=1}^{20}\frac{\$18}{1.05^i}=\$1{,}025/\text{kW}$. Thus, the total cost of a 25-MW segment equals $26 million.

The total present value cost of the wind plant equals the expected discounted cost of when each segment is installed. As discussed in Reference 4, the expected cost of an investment equals $C_0\left(\frac{1}{1+r/p}\right)^L$, where C_0 is the investment cost, r is the real discount rate, and p is the probability of the load growing in a given year (0.5). In this analysis, L equals 1, 2, 3, and 4 for the first, second, third, and fourth wind plant segments. Since $\left(\frac{1}{1+r/p}\right)$ equals $\left(\frac{1}{1.1}\right)$, the total expected wind plant cost is $26\left[\left(\frac{1}{1.1}\right)^1+\left(\frac{1}{1.1}\right)^2+\left(\frac{1}{1.1}\right)^3+\left(\frac{1}{1.1}\right)^4\right]$, or $82 million.

Natural Gas-Based Plant Costs

Three costs associated with the natural gas-based plant are its capital cost, fuel cost, and potential future environmental costs. In terms of the capital cost, a 50-MW natural gas plant has a $25 million capital cost if its per unit cost is $500/kW.

In terms of the fuel cost, the natural gas plant is operated so that it produces the same amount of energy per year as the wind plant. For example, if only one segment of the wind plant is on-line, then the gas plant has a 20% annual capacity factor. The risk associated with natural gas price fluctuations is mitigated by committing to purchase four sets of 20-year natural gas contracts, one for when each of the four wind plant segments would have been needed. Each contract will supply 87.5 GWh/year worth of fuel (i.e., the same amount of electricity as produced by the 25-MW segment of the wind plant).

This requires a natural gas contract of 525,000 MBtu, assuming a constant heat rate of 6,000 Btu/kWh for simplicity. If the contracted natural gas price is $2.50/MBtu, then the annual contract cost is $1.3 million (this translates to an annual energy cost of $0.015/kWh). If this is the contracted price for 20 years, then this cost, discounted at the rate of debt over a 20-year period, equals $\sum_{i=1}^{20}\frac{1.3}{1.05^i}=\$16$ million.

The expected present value cost of these four fuel contracts must be calculated because the contracts are not entered into until each segment of the wind plant would have begun operation. The calculation is similar to that performed for the wind plant cost. The only difference is that the contract costs occur one year later (and thus must be discounted by an additional year) than the wind plant costs because there is no lead time associated with the fuel contracts. The present value cost of the four fuel contracts equals $\left(\frac{16}{1.05}\right)\left[\left(\frac{1}{1.1}\right)^1+\left(\frac{1}{1.1}\right)^2+\left(\frac{1}{1.1}\right)^3+\left(\frac{1}{1.1}\right)^4\right]$, or \$48 million.

The third cost is the potential cost associated with future environmental regulations. While there are many potential regulations that could affect the cost of the natural gas-based plant, only the potential cost of carbon emissions because of the government developing regulations because of problems with global warming is considered.

There are 0.0145 tons of carbon/MBtu of natural gas (Ref. 9). Thus, the annual carbon emissions for each fuel contract equals 7,600 tons of carbon (0.0145 tons of carbon/MBtu times 525,000 MBtu). There is a total annual emissions of 30,450 tons of carbon when all four contracts have been purchased.

Bernow, et. al. (Ref. 10) have developed a set of scenarios of the potential future costs associated with carbon emissions. They have cases of no taxes, medium taxes (\$37/ton), and high taxes (\$110/ton).

By year 10, Figure 2 indicates that the full output of the wind plant is needed and thus the natural gas-based generation will be producing at its full power (i.e., demand will have grown sufficiently to require all of the generation). Assume that the carbon taxes are instituted in 2005 and that they last for 10 years of the plant's life. The total present value cost equals $\sum_{i=11}^{20}\frac{(tax)30{,}450}{1.05^i}=(tax)(144{,}350)$ so that the present value cost is \$5 million at a tax rate of \$37/ton and \$16 million at a tax rate of \$110/ton. If it is assumed that each of the three possible tax rates are equally likely, then the expected cost associated with carbon emissions equals \$7 million.

The total cost of the natural gas-based generation equals the sum of its capital, fuel, and potential environmental costs. This total equals \$25 million + \$48 million + \$7 million, or \$80 million. This cost is almost identical to the wind plants cost of \$82 million.

CONCLUSIONS AND FUTURE DIRECTIONS

Regulatory and technical forces are causing electric utilities to move from a natural monopoly to a more competitive environment. This change is causing an increasing concern about how to manage the risks associated with the electric supply business. This paper discussed the risk-mitigation potential of renewable energy technologies from several ownership perspectives. Specific attention was given to the attributes of fuel costs, environmental costs, modularity, lead time, availability, initial capital costs, and investment reversibility.

The conclusion of this research is that renewable energy technologies, particularly the modular technologies such as wind and photovoltaics, have attributes that may be attractive to a variety of decision makers depending on the uncertainties that are the greatest concern to them.

An illustrative example of a municipal utility considering either wind or natural gas-based generation shows that the consideration of risk attributes could significantly affect the decision process.

A full report that develops the equations for the discussed risk factors as well as presenting illustrative examples for wind and photovoltaic technologies with different project owner perspectives is forthcoming. We plan to carry the work further by applying a comprehensive set of risk factors to actual utility situations and future potential decisions through collaboration with decision makers and plant owners.

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