US energy policy is a mix of federal, state, and local directives. Nevertheless, the convergence of smart technology, environmental regulation, renewable energy sources, and market prices are combining to reshape the electric energy industry.

Whether in regulated or deregulated markets, stakeholders are looking for easy-to-understand decision-making metrics to guide energy development choices. Often these choices depended on a mix of competing decision criteria. Decisions will often depend on future uncertainties.

Although uncertainty complicates the decision criteria, risk management tools can be used to evaluate competing investment choices and help predict the direction the industry will take. In this article, we show how value at risk and risk-adjusted return can be used to help determine the optimal amount of load management programs, renewable energy sources, and other alternative energy sources.

The choice between alternative energy and traditional energy sources is often determined by comparing the cost and benefits of each. Using an integrated-resource, least-cost decision criteria, the optimal mix of resources will provide the best overall value for society. Often benefits are monetary. Sometimes benefits include tangibles and intangibles. For example, job creation, clean environments, long-term market effects, and other intangible benefits are often included in the decision process.

For example, Nevada Power Company recently reported in its filing to the public utility commission several key benefits of its demand-response programs. These programs are evaluated based on the avoided costs of alternative fossil generators. Avoided costs typically include both avoided generation and avoided capital construction (deferred capacity, see Sidebar).

Nevada Power’s filing includes several avoided costs:

- Avoided capacity
- Avoided fuel and purchased power
- Deferred distribution system upgrades

However, the company also notes that several important benefits are not reported, including the following:

- Avoided capacity options
- Reliability benefits from using the program to prevent brownouts or blackouts

A first set of benefits represents the expectations and value of purchasing energy for business as usual. A second set represents potential benefits in the rare and unlikely case of system emergencies. It just so happens that demand-response programs can provide both benefits.

However, the analysis of the second set of benefits is a bit more complicated and often left out of the calculations. This omission results in undervaluing demand-response programs and requires more fossil generation than would otherwise be needed. The analysis is complicated because the value represents the option value or insurance value of owning a peak-hour resource.
expected output if the price rises or sell output in future years to lock in profits on electricity it has yet to generate. Duke did this with a pair of “peaker” plants it built in Indiana and Ohio, locking in the first year’s expected profits before construction was completed.

If the traders sense that a market is becoming too competitive, they may call for the outright sale of the plant. Duke did that in Hidalgo, Texas, where it sold a majority stake in a 500-megawatt plant for $235 million to Calpine in 2000, three months before it was completed, and mothballed five other projects in the face of rampant overbuilding. (Fisher, D. [2002]. Trading places, Duke Energy was once considered the hopelessly asset-encumbered version of Enron. Nowadays that’s not such a bad thing. http://www.forbes.com/global/2002/0121/026.html)

In this example, Duke viewed its assets as holding inherent value, based on the existing market conditions and the competitive landscape, and acted on new information as markets changed, unlocking additional extrinsic value. Duke is able to generate revenue from its power plants in a number of ways. Typically a marketer sells long-term forward power and buys long-term forward natural gas to hedge the inherent intrinsic value. Having sold the electricity and purchased the gas, the marketer’s position increases in value when the price of electricity decreases and the price of gas increases (the spark spread narrows) but decreases in value when the price of electricity increases and the price of gas decreases (the spark spread widens). The marketer has entered into a short spark-spread position.2

Additionally, by controlling the generator Duke is naturally long a spark-spread call option. On days when the spread is zero or higher, Duke will run the generator. On days when the spread is negative, Duke will idle the power plant and unwind the gas and electricity positions by selling the gas and purchasing electricity to supply its obligation. Together the sort position and the long call option are equivalent to a long put option on the spark spread—the margin is fixed and largely determined by the economic heat rate of the plant when it is running, but varying and dependent on the market when the plant is idle.

In this example, we demonstrated that power plants have both intrinsic and extrinsic value. The

Options and insurance policies both require a precise understanding of the risks and uncertainties characterizing the underlying resource.

POWER PLANTS ARE REALLY A CALL OPTION

Modeling and valuing fossil power plants as contingency options is not new. Commodity traders use the term intrinsic to describe the business as usual value and extrinsic to describe the value of hedging against future uncertainty. As an illustration, in 2002, in discussing Duke Energy’s diversification strategies, Daniel Fisher points out that Duke has traditionally viewed every asset as holding both intrinsic and extrinsic value.

The intrinsic value is the ability for the asset to make money. For a power plant, that includes its location and the efficiency with which it transforms gas into electricity. Duke can’t do much to change the inherent value of its assets, and it assumes that competition will eliminate any edge it has anyway.

The only way to make money, therefore, is to maximize the extrinsic value by trading around the assets. When it builds a power plant, for example, it sells some of the expected output in the forward market and buys the gas to fuel that output. As construction proceeds, the difference between the price of gas and the price of electricity widens and narrows, giving Duke the opportunity to sell more of the

Avoided Costs

The Public Utilities Regulatory Policy Act of 1978 requires the Federal Energy Regulatory Commission (FERC) to adopt regulations requiring electric utilities to purchase electric energy from Qualifying Facilities (QFs).a The rate at which an electric utility is required to pay a QF for electricity must be just and reasonable, in the public interest, and cannot discriminate against the QF. However, the rate cannot exceed the incremental cost to the utility of alternative electric energy. The incremental cost of alternative electric energy is commonly referred to as the avoided cost and is generally defined as the “cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source” (18 C.F.R. § 292.101(b) (6)).

a FERC’s regulations on avoided costs and Qualifying Facilities are in 18 C.F.R. Part 292.
same benefits exist with demand-response programs and other alternative energy sources. In the case of a demand-response program, the intrinsic value is based on the existing market conditions, reserve margin, and the competitive landscape. The extrinsic value is equivalent to owning a reliability option where the underlying is the spread between system capacity and actual load. It represents an insurance policy against low-probability, high-consequence events.

Other option value exists as well. For example, a demand-response program can be scaled up or scaled down by adding more or less participants as information about summer resource adequacy becomes available. Demand-response programs can also be used to delay costly infrastructure development projects.

In the case of the Nevada Power demand-response programs, the intrinsic program value is calculated using a traditional net present value (NPV) calculation. The discounted cost of the program over a 10-year program life is compared to the discounted revenue (or avoided cost benefits). The total discounted cost of the commercial program is about $36.3 million. The discounted value of the benefits is about $89.7 million. The net benefit is $53.4 million, with a benefit-cost ratio of 2.47.

The extrinsic value is calculated by evaluating the market value of system emergencies times the probability of emergency conditions. The system is not expecting emergencies, thus the value of this protection is not included in the net present value calculations described above. The added value can be calculated using the same tools that insurance companies use to price insurance policies, or that commodity traders use to price options.

Both the intrinsic and extrinsic value are graphically shown in Exhibit 1. It shows the value of energy and capacity at various market-price and weather extremes. The insurance or option payoff is shown with the solid line. As the system prices increase due to potential system emergencies, the value of the program increases comparably.

Analytically, the value is calculated in two parts. The intrinsic value is evaluated using expected prices and weather conditions. The extrinsic value is calculated as an additional “at the money” option. The additional value times the appropriate probabilities is evaluated for all conditions above expectations. In our example, the added insurance value is equal to $9.6 million. Adding the extrinsic and intrinsic value, the total value is equal to $63 million. In our example, excluding the extrinsic value is equivalent to over a 15 percent error, resulting in less demand response to be developed than would be optimal.

**RISK ADJUSTING AND DEMAND RESPONSE**

The insurance or option value highlights the upside benefit of alternative energy projects, but what about the downside? How can the risks facing the various alternatives be included in the overall evaluation?

Most asset planners would agree that there should be a direct relationship between risk and return in any investment decision. However, current alternative energy investment methods do not do a good job of trying to understand whether the choices reflect appropriate returns for the risk they face. Additionally, investment criteria often look at individual asset investments, rather than the collection of assets (portfolio) as a whole.

Efficiency frontier analysis is a portfolio analysis concept that evaluates risk/return for portfolios that can be composed of a given group of investments and identifies the single highest level of expected return for a given portfolio risk profile. It requires information about individual investment opportunities, including expected return and the standard deviation of return (a measure of risk). Exhibit 2 shows the efficiency frontier for a given portfolio. Anywhere along the line is efficient. Points below the line represent inefficient investments that require higher risk relative to the expected returns compared to alternatives.
For risk management purposes, the main goal of allocating capital to individual energy investment activities is to determine the optimal capital structure—that is, economic capital allocation is closely correlated with individual energy investment risk. As a performance evaluation tool, it allows society to assign capital to energy investments based on the added economic value.

RAPM can be extended to firmwide risk measures:

$$\text{marginalRAPM}_i = \frac{\text{Profit}}{\Delta \text{VaR}_i},$$

where $\Delta \text{VaR}_i$ is the change in total VaR due to an increase in the allocation to $i$. This measure can be used as a guide to enter into a business activity. Risk-adjusted performance metrics can be used to identify where stakeholder value is being added throughout the energy investment portfolio and to help regulators make decisions about which energy investments to expand or reduce.

We noted earlier that a demand-response program can be scaled up or scaled down by adding more or fewer participants as information about summer resource adequacy becomes available. In addition to adding optionality, this feature further reduces the risk and improves the risk-adjusted return compared to traditional fossil generators. Using these criteria, we find that the current decision methods favored by utility commissions have significantly undervalued alternative energy choices by ignoring both the insurance value and the risk-adjusted return of alternative energy choices.

NOTES


2. More discussion of these considerations is found in this issue of *Natural Gas & Electricity* in Tanya Bodell’s column, “A Midsummer Night’s Dream: Why Natural Gas Prices Still Sleep”—Ed.

3. Most public utility commissions use tests outlined in the 2002 California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects (http://www.energy.ca.gov/greenbuilding/documents/background/071_CPUC_STANDARD_PRACTICE_MANUAL.PDF) to measure the cost-effectiveness of energy-efficiency and demand-response programs. In this example, we are referring to the TRC (Total Resource Cost) test.

4. Ibid.