Welcome to the New Era of Resource Planning: Why Restructuring May Lead to *More* Complex Regulation, Not Less

To prepare themselves, utilities will need to develop much more rigorous analytical tools. The standard analytical toolbox, relying on deterministic production–cost models, cannot be used to evaluate many of the new supply alternatives. Second, to the extent utilities begin to rely on these supply alternatives, they will need to justify their supply decisions to regulators, even if utilities decide to let third parties completely manage their supply portfolios.

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I. Introduction

Although electric utility restructuring was supposed to deregulate wholesale and retail generating markets, the majority of electric utilities have retained obligations to supply some or all customers. The debacle in California's electric market changed the impetus for retail competition in many states. As a result, restructuring efforts have slowed markedly and the goals of restructuring are being reconsidered. These changes in restructuring's fortunes have important implications for utilities and their customers. The vast majority of utilities are still saddled with a traditional obligation to serve. At the same time, utilities are more frequently using risk-management tools to meet their supply

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obligations, which remain under regulatory scrutiny. These tools, however, do not fit neatly into the traditional resource planning regulatory framework, which seeks ''least-cost'' prudent supply management.

Regulators, whose focus had previously been establishing stranded cost values and overseeing the breakup of electric utilities, are now faced with an industry that is far more complex, yet still requires ''traditional'' oversight. Regulatory issues, including establishing allowed returns on equity, rate structures, performance-based measures and, perhaps most fundamentally, ensuring sufficient generation to meet an ever-increasing demand for electricity, remain important. A perhaps more vexing regulatory issue is the notion of ''prudence'' of risk-management efforts by utilities seeking to protect themselves from volatile, and sometimes illiquid, wholesale markets.[1]

Resource planning requirements and prudent risk management are inexorably linked. Utilities need to employ more sophisticated analytical tools that focus on uncertainty surrounding future customer demand, market prices, and even the potential for new regulations. To do this, utilities need new analytical tools that can evaluate long-term resource strategies in the face of uncertainty, and guidance as to whether selected resource strategies meet regulatory ''prudence'' standards. This article discusses both needs.

II. The New Realities of Resource Planning

It is perhaps ironic that as the electric market has become far more complex, there are probably few utilities devoting much effort to resource planning exercises that can effectively sort out those complexities. While more utilities are engaging in day-to-day trading operations, many long ago exorcised their resource planning staffs. Regulators, however, have apparently been too mired in restructuring *per se* to care. Yet, the need for careful planning has not gone away. The potential choices faced by utilities in meeting still-present demand obligations have exploded, as have the tools necessary to evaluate those choices.

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These new choices for resource planning attempt to take advantage of the uncertainty in the wholesale generation markets. Most utilities now purchase short-term contracts to supply some of their peaking capacity to cover the uncertainty in their peak summer loads. Similarly, utilities receive both solicited and unsolicited offers for base load generation. Most of these offers are in the form of purchase-power contracts (PPAs) with considerable flexibility in the amount of generation offered, pricing, and the terms of contract renewal. The actual value of these flexible contracts can be assessed only by taking into account the uncertainty now established in the market.

The explosion in resource supply choices is the direct result of deregulated wholesale markets and rapid advances in risk management. As years' worth of excess generating supply were steadily absorbed by unexpectedly large increases in demand, prices in expanding wholesale markets became more volatile. Historic spikes in oil prices and rapid increases in the demand for natural gas exacerbated electric price volatility. As a result, utilities and regulators have become more focused on ways to stabilize costs and prices; utilities because volatile costs could increase risk and adversely affect shareholder returns, and regulators because volatile prices could increase ratepayer anger and political disapproval. Not least, the pace of technological change continues to increase. New resource options are providing greater flexibility for utilities and their customers, but also further complicating the decision process.

Enter risk management, offering utilities ever more exotic financial instruments to hedge their risks and reduce the impacts of volatile markets . . . for a price. That price includes the obvious affects of insurance—raising costs to a higher average level than benefits received—and, rarely, the catastrophic impacts of ''rogue'' utility traders who speculated in generating markets, rather than hedged their companies' risks. It also includes additional regulatory scrutiny: after all, insurance is truly valuable only when the unexpected happens, providing regulators a potential avenue for deeming insurance costs as imprudent or, if the insurance is used, damning a utility for poor planning.

In this new era, uncertainty about the future has become a looming issue: markets have become more volatile, restructuring plans have changed radically, and utilities have changed themselves. Traditional planning tools do not address the opportunities and risks with stochastic markets and new options whose values are inexorably linked to those markets. Resource planning must also adapt to this new market environment.

A. A new market-based approach for resource planning

To understand the new approach to resource planning, it is useful to consider a specific example that is based on an actual evaluation we performed. A utility operating in a state that has not yet restructured has experienced relatively steady load growth over the last decade. While it can purchase wholesale electricity from the spot market, that market has been notoriously volatile since its inception. That volatility has created both earnings and regulatory risk, the latter in the form of potential disallowances for purchasing generation supplies that are either imprudent, not used-and-useful, or both.

Since the utility continues to have an obligation to serve, suppose it must make several decisions about the makeup of its resource portfolio. One of those decisions concerns an offer to purchase an option for a purchase-power agreement offered by a large wholesale generating company. The PPA is structured like a financial call option, with a few twists from the usual finance examples. First, the utility can select the duration of the PPA (one, three years, etc.) and the magnitude of the purchase (100, 500 MW, etc.). The utility can also decide at what rate it wishes to take the energy and whether it wishes to take it whatsoever. Second, the ''strike'' price for the option—in this case, the price at which energy would be provided—will be a weighted average of the then-prevailing prices of natural gas and fuel oil at the beginning of the year.[2] How should the utility determine whether the PPA is a good deal and whether regulators are likely to view a decision to acquire the PPA as prudent?

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The traditional production–cost model evaluation approach commonly applied to resource planning decisions in the pre-restructuring era might have evaluated the PPA as follows:

1. Run a production–cost model, assuming some level of load growth and a forecast of electric and fuel prices, without the PPA.
2. Run the same model with the PPA.
3. Compare the present value costs to the utility with and without the PPA, and determine whether or not inclusion of the PPA reduces present value costs. If the present value is lower with the PPA than without, the utility should sign the agreement.

Applying this traditional approach to valuing the PPA would totally ignore the market uncertainties and demand uncertainty that gives the option its potential value. Nor can it incorporate specific hedge mechanisms that the utility might wish to employ to reduce the magnitude of ''bad'' outcomes (e.g., high PPA cost, low market value).

Instead, the PPA needs to be valued using a probabilistic approach, such as the Black–Scholes model that is used to value stock options.[3] Although the Black–Scholes option pricing model is a fundamental aspect of financial economics, it is often inappropriate to use to value energy options. Although a complete discussion of the reasons why it is inappropriate is far beyond the scope of this article, those reasons boil down to an inability to consider multiple uncertainties and unrealized assumptions about the behavior of market prices. In the PPA example, there are a number of market uncertainties, the exercise prices may not be known in advance, and the price of the PPA without the flexibility of its options is not known from active trading on a market exchange.

To address these complexities, one common approach is to use Monte-Carlo methods to develop a stochastic valuation model. Monte Carlo is a simulation technique in which ''random'' values of the underlying uncertainties are ''drawn'' repeatedly. After a sufficient number of ''draws,'' one can obtain a probability distribution of the value of the option.[4] This not only tells us what the expected (average) value of the PPA option is, but also the likelihood that it will have any value whatsoever, far more useful information than would be provided by simply comparing two deterministic cost estimates.

In the case of the PPA option, the utility will want to determine both its underlying value and its usefulness as a long-term hedge against future market volatility. The latter can be thought of as the equivalent of value-at-risk (VaR), which is often used by financial trading organizations to evaluate near-term risk exposure.[5]

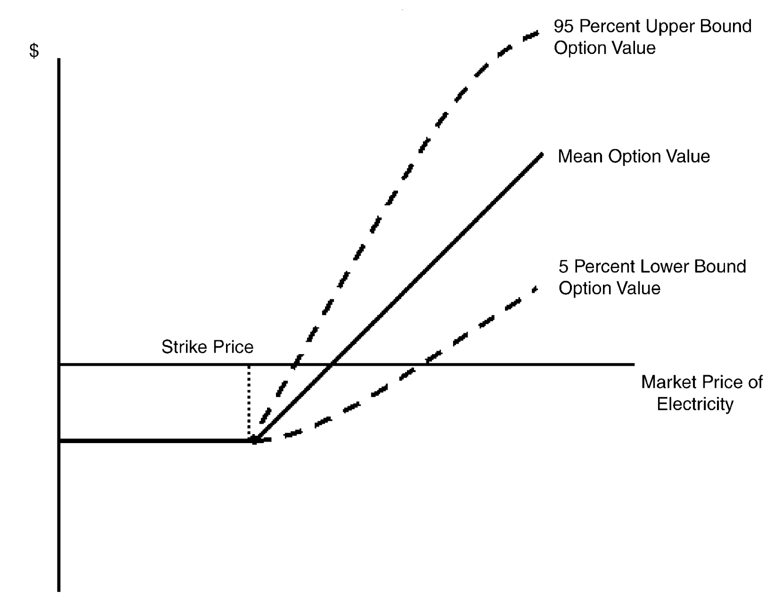


Figure 1: Probability Distribution of PPA Option Value

Unlike a typical financial option where the future strike price is known with certainty, the multi-uncertainty Monte-Carlo PPA model would yield a probability distribution of option value. For example, **Figure 1** shows the 5 and 95 percent lower and upper bounds for the value of the PPA option relative to electric prices. Below the ''strike'' price, the utility would not exercise the option and its value would equal the initial PPA option purchase price. Above that strike price, the value of the option would depend on underlying fuel prices and load growth.

Figure 2 presents an alternative way of looking at the PPA value. This figure shows the option's overall cumulative probability distribution, often called a ''risk profile.'' In Figure 2, the risk profile is just below zero (the option's purchase price) 45 percent of the time and then rapidly increases in value. The option has the greatest value when fuel prices are comparatively low, electric prices are high, and the utility's own loads are low.

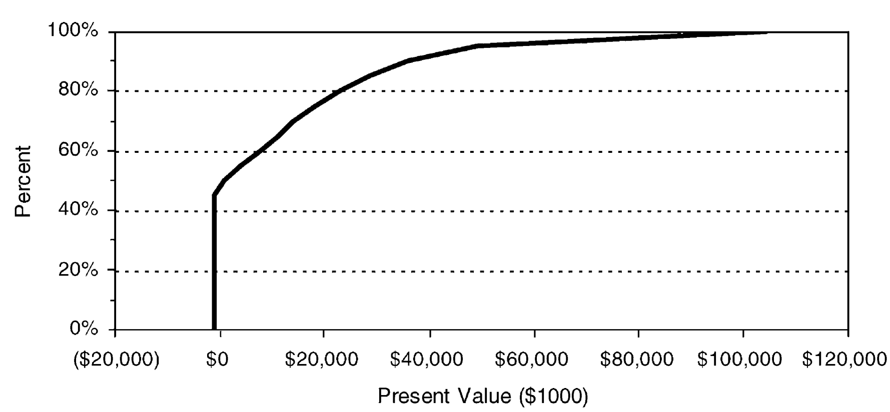


Figure 2: PPA Option Risk Profile

B. Evaluating resource portfolios and ''real-option'' values

Utilities should also evaluate new resource opportunities in the context of their overall impacts on entire resource portfolios, just as financial investors consider their overall portfolios of stocks, bonds, and cash reserves. Diversification of risk may be a crucial regulatory requirement and the risk impacts of an individual resource may be quite different when viewed as part of an overall portfolio.

While many traditional least-cost planning rules stress the need for ''diversity,'' little effort was devoted to defining diversity in an operational sense. In general, diversity meant fuel diversity, as fuel price uncertainty, especially uncertainty about crude oil prices, assumed greater importance after the first OPEC oil embargo in 1974. The approach to evaluating fuel diversity, however, almost always was the deterministic one of production–cost models. As a result, the value of diversity was neither clearly defined nor accurately measured, since the value of diversification stems from its ability to reduce portfolio risk.

Diversity, of course, is not one-dimensional; there are many types of risk and many approaches to diversifying those risks, notably by incorporating ''flexibility'' into resource planning decisions. The value of flexibility, better known as ''real-option'' value, arises from inherent market uncertainties, such as wholesale electric and fuel prices, as well as non-market uncertainties, such as changes in state and federal environmental regulations.

Estimating the risk profiles and embedded real-option values in portfolios of generating resources can be accomplished using a variety of analytical techniques, such as dynamic programming and Monte-Carlo simulation.[6] While space precludes a discussion of these techniques, **Figure 3** provides a schematic representation of a Monte-Carlo simulation model that captures the overall value of flexibility embedded in both the wholesale spot market and the market for ancillary services. **Figure 4** provides a representation of a resource portfolio risk–return frontier. In this figure, portfolios A, B, and C all have different risk–return characteristics. None of the portfolios is ''dominant'' (i.e., greater return and less risk), and so the utility's choice of resource portfolio is not

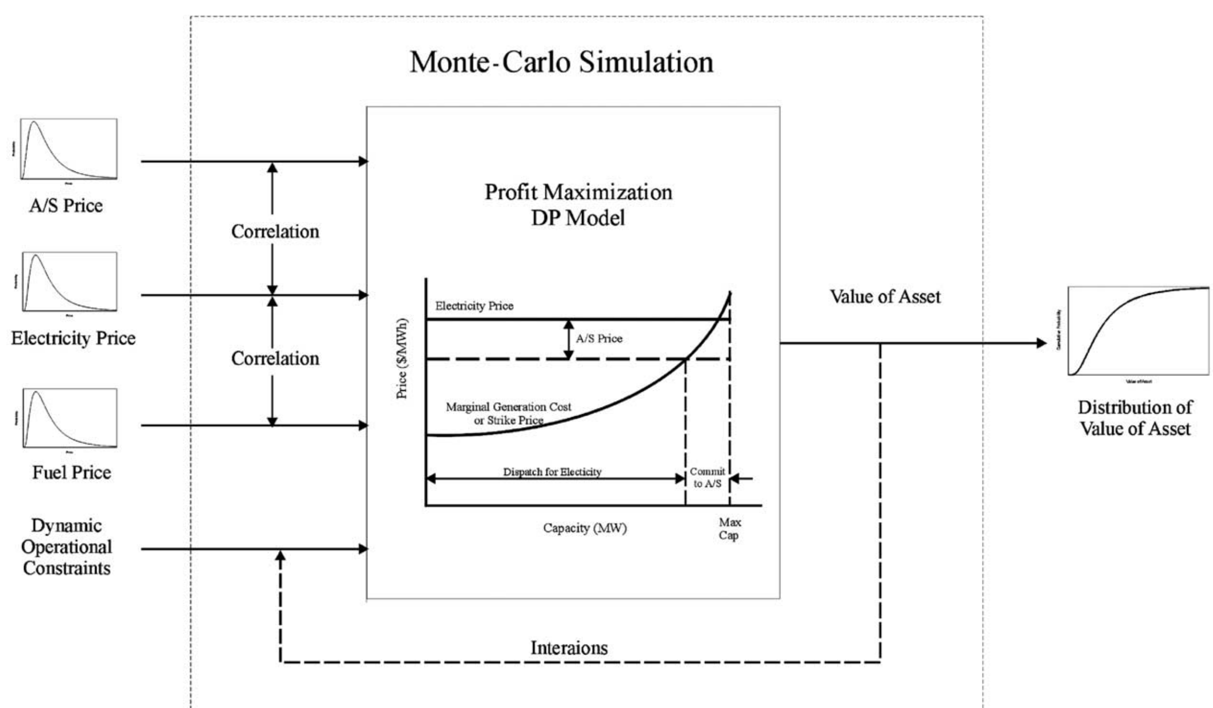


Figure 3: Schematic of Option Valuation Model

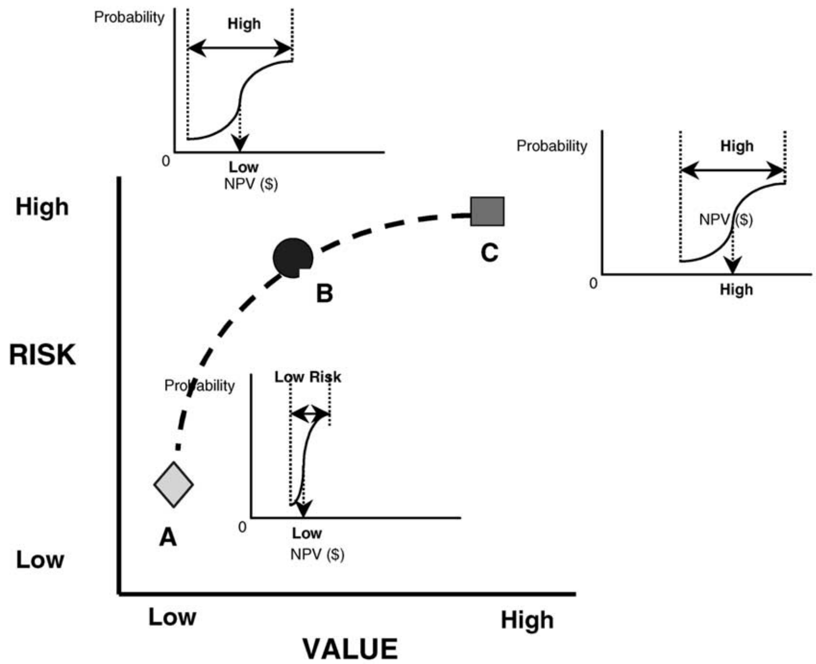


Figure 4: Development of Risk–Return Tradeoffs for Resource Portfolios

clear.[7] Rather, it will depend on the preferences of the utility's management, its customers, and especially its regulators. That is the subject of the next section.

III. Determining Prudent Risk-Management Activities

Would purchasing a PPA contract like the one discussed previously be prudent? Would it be considered used-and-useful even if the utility chose not to exercise the option? In general, what constitutes a ''prudent'' utility resource investment decision in the presence of uncertainty when the utility considers risk-management instruments designed to lessen the impacts of uncertainty? Whereas these questions are straightforward, their answers are not.

That the future is uncertain notwithstanding, the legal interpretation of prudence has changed over time. Certainly, in the first half of the 20th Century, the courts did not envision the existence of complex financial markets and instruments. Fundamental financial relationships, such as the Black–Scholes model formula simply did not exist. Nor was volatility in electric markets envisioned, as there was no open and competitive electric market whatsoever.

The prudence standard, which is sometimes called the ''prudent investment rule,'' dates back to *Southwestern Bell*, decided by the U.S. Supreme Court in 1923. In that case, Justice Brandeis wrote a separate, concurring opinion stating that:

> There should not be excluded from the finding of the [rate] base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown . . ..[8]

That decision, and its application over the next 75 years, established two fundamental principles of ratemaking. The first is that expenditures that were reasonable and prudent are to be included in rates. This is part of the just and reasonable standard adopted by most states. The second is that a presumption of prudence exists with regard to a utility's expenditures, and that overcoming the presumption requires clear evidence of misconduct by the utility (e.g., ''dishonest or obviously wasteful or imprudent expenditures'').

In utility regulation, the prudence standard usually (but not always) begins with a recognition that the concept itself relates to *decisions* or, in some cases, the lack of a decision, rather than to *results*. It is the decision-making process by which these results are achieved that is judged, not the results themselves. Within that framework, three overriding principles must be considered in developing any prudent management standard to be applied in a ratemaking proceeding:

(1) The prudent management standard must be able to be consistently applied across a wide range of circumstances; the application of the standard should not be dependent upon the nature of the costs being reviewed or the rate resulting from the application of the standard.

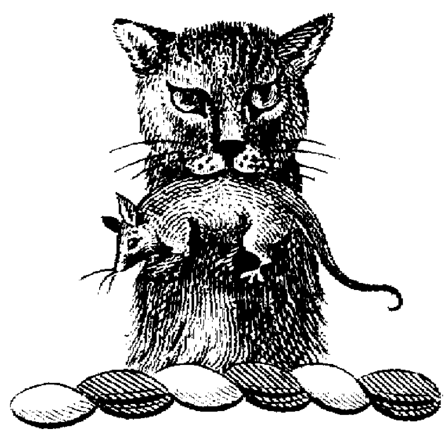
(2) The entire concept of ''reasonableness'' is premised on the belief that there is a range of acceptable behavior, and that in order for a cost to be disallowed, the decision resulting in that cost being incurred must be demonstrated to have been outside the range of reasonable behavior based on circumstances as they existed at that time.

(3) The prudent management standard must adequately balance the interests of ratepayers and investors, and provide a reasonable incentive for the utility to provide reasonable service at a reasonable cost.

The prudence standard calls for a balanced, retrospective review of the decisions and conduct of the utility's management. The application of the prudence standard formed the basis for recommendations developed by the National Regulatory Research Institute (NRRI), the research arm of the National Association of Regulatory Utility Commissioners. In an April 1985 study, *The Prudent Investment Test in the 1980s*, the NRRI set forth four guiding principles for a prudent management standard to be incorporated in the ratemaking process for public utilities:

> Review of the many recent state commission applications of the standard suggest four guidelines for successful use of the prudent investment test. These are, first, that there should exist a presumption that the investment decisions of the utilities are prudent . . .. The second guideline is to use the standard of reasonableness under the circumstances . . . a corollary to the standard of reasonableness under the circumstances is a proscription against the use of hindsight in determining prudence; observing this proscription is the third guideline. The fourth guideline is to determine prudence in a retrospective, factual inquiry. Testimony must present facts, not merely opinion, about the elements that did or could have entered into the decision at the time.[9]

There is one further point. Because only prudent costs



can be included in rates and prudence determinations are a retrospective exercise, once the investment becomes eligible for inclusion in rates the prudence review should be conducted as soon as possible, and the prudence of that cost should be decided for all time. Cost-based ratemaking compensates utilities for ''prudent investments at their actual costs when made . . . irrespective of whether individual investments are deemed necessary or beneficial in hindsight.''[10] Thus, in theory prudence is not judged on ''results,'' but on whether management's actions were reasonable at the time the decision was made to incur the cost. Once that determination has been made, the treatment accorded the costs associated with those decisions should be finalized.

A. The ''used-and-useful'' standard

Related to the prudence of utility decisions is the used-and-usefulness of those decisions. Although related, prudence and used-and-usefulness have different applications and, regarding risk-management decisions and instruments, used-and-usefulness may be hotly debated in a regulatory context.

The used-and-useful concept evolved as a way to allow regulators to scrutinize utility rate base, and allow a return only on ''the value of the property used, at the time it is being used, to render the services [to ratepayers].''[11] This concept was resurrected and applied by a number of advocates in the 1980s, primarily in conjunction with prudence reviews of nuclear power plants where capital costs exceeded original forecasts.

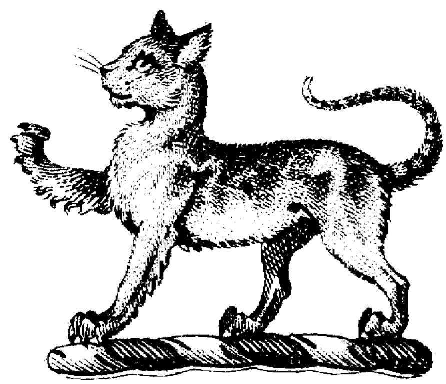
In light of market-based risks, the courts have interpreted used-and-useful in different ways. One well-known case, *Market Street Railroad*,[12] has often been cited by proponents of after-the-fact, results-based reviews of utility decisions. The Market Street Railway Company was a San Francisco trolley company that faced increasing competition from automobile traffic and had been ordered to reduce its rates by the California Railroad Commission. The railroad argued that the rate reduction constituted an unconstitutional ''taking'' of its property. The Supreme Court disagreed, ruling that an entitlement to earn a ''fair rate of return'' was not the same thing as a guarantee.

The applicability of *Market Street Railroad* to after-the-fact regulatory decisions concerning the used-and-usefulness of electric utility risk-management instruments (or, indeed regulated utility decisions in general) seems tenuous at best. Whereas the trolley company faced inexorable competition from the growing use of automobiles, electric utility ''competition'' has been imposed by—as evidenced in California regulators' prohibition on the use of forward market instruments by utilities—regulators themselves.

Under such an *ex-post* regulatory interpretation, hedging instruments could be particularly vulnerable, as they are expected to result in a net loss by design. For some risk-management instruments, such as forward market purchases designed to ''lock in'' a set of prices, the structure of the instrument will never be ''optimal.'' Whereas if the forward price is greater than the realized market price, the utility might be viewed as imprudent for having made its forward market purchase, if the forward price is lower, the utility might be viewed as imprudent for not having purchased greater quantities in the forward market. This begs the question of whether the utility (and its regulators) can agree on methods to make *ex-ante* risk-management decisions.

B. The role of regulators

As financial-type instruments become more widely used by utilities to meet their electric power supply obligations, those utilities will not only have to employ sound analytical methodologies with which to choose among competing instruments, they will have to justify those



choices to regulators. Unfortunately, the entire concept of risk-management and financial-market instruments in the context of regulated utilities is poorly defined. While regulators often discuss requirements that utilities ''diversify'' away risk, it is not always clear what sort of risk is to be diversified, nor why it should be diversified, nor an appropriate method for diversifying. Lastly, arm-chair quarterbacking remains an issue. Regulators, perhaps under pressure from constituents and politicians, can be tempted to revise assessments of utility actions after the fact. Since many market-based financial instruments are insurance vehicles, utilities cannot expect them to reduce average costs. What they can do is reduce the volatility of costs. At the same time, other market instruments, such as the PPA option described, must be carefully assessed so as not to increase utility risk.

Defining ''prudent'' utility resource decisions has always been controversial, as the long and messy legal history of prudence attests. Certainly, in the first half of the 20th Century, regulators and the courts did not envision the ever-growing set of complex financial instruments now available to utilities. Fundamental financial models, such as the Capital Asset Pricing Model (CAPM) and the Black–Scholes option pricing formula simply did not exist. Nor was volatility in the electric market envisioned, as there were no competitive wholesale electric markets. As generation supply alternatives take on more characteristics of financial instruments, evaluating their prudence is certain to become more difficult, and thus, more controversial, especially in the face of failed industry restructuring efforts.

To prepare themselves, utilities will need to develop much more rigorous analytical tools. First, as we saw in the PPA example, the standard analytical toolbox, relying on deterministic production–cost models, cannot be used to evaluate many of the new supply alternatives. Second, to the extent utilities begin to rely on these supply alternatives, they will need to justify their supply decisions to regulators, even if utilities decide to let third parties completely manage their supply portfolios. As a first step, utilities and regulators will need to agree to certain guidelines. These include:

1. *Transparency of outcomes and adherence to standard accounting practices*. This means that the results of the utility's power supply and risk-management activities must be clear to all parties and follow established accounting guidelines for value-at-risk (VaR) accounting, which determines the overall volatility of earnings in a specific time period.

2. *Clear incentive structures*. Regulators need to ensure that incentive mechanisms for the utility, in terms of profit-sharing and price caps, are well defined. The incentive structure cannot be ''heads we win, tails you lose.'' There must be symmetry of risk and reward between the utility shareholders and ratepayers.

3. *Well-defined risk-management goals within which a utility may operate*. Because financial distress can have adverse impacts on ratepayers, regulators must also determine maximum acceptable risk exposure levels. If regulators wish utilities to insure against excessive price volatility, for example, they must define acceptable levels of volatility and an acceptable average cost. This will require measurable objectives and attributes that can (and should) be incorporated into a clear incentive structure for the utility. Above all, despite huge temptation, regulators should not ''punish'' utilities after the fact if the utility has been operating under such previously established guidelines. This does not preclude changing existing guidelines, which will probably need to occur as the financial instruments available to utilities continue to evolve, but such changes should not punish a utility for a lack of clairvoyance.

C. Some final thoughts

To be useful, resource planning must continue to evolve. Most utilities will continue to retain their obligation to serve in the face of considerable market risks. Utilities will need to evaluate an expanding array of resource options, many of which will have little in common with the traditional resource options that were standard fare for utility planning exercises as little as five years ago. Today, as the planning and regulatory hiatus imposed by restructuring appears to be ending, utilities must gird themselves for new resource decisions in an era of great uncertainty and rapid technological change.

As the supply options available take on more characteristics of financial instruments, traditional deterministic planning tools must be supplanted to provide robust evaluations that specifically incorporate future uncertainty. These tools will also be needed to successfully defend utility decisions that manage the effects of risky markets in a regulatory environment that is likely to remain contentious and politicized.■

Endnotes:

1. For a brief introduction, see Edward Krapels, *Determining Prudence in a Hypervolatile and Illiquid Market*, ELEC. J., May 2001, at 38–40.

2. The PPA offer can thus be thought of as a type of spark-spread option.

3. For a general theoretical introduction to the problem of valuing investments in the presence of uncertainty, see AVINASH K. DIXIT AND ROBERT S. PINDYCK, INVESTMENT UNDER UNCERTAINTY (Princeton, NJ: Princeton Univ. Press, 1994). An introduction to energy derivatives pricing can be found in DRAGANA PILIPOVIC, ENERGY RISK: VALUING AND MANAGING ENERGY DERIVATIVES (New York: McGraw-Hill, 1997).

4. The actual precision of the estimate will depend on the number of uncertainties modeled and the number of draws made. See, for example, GEORGE W. SNEDECOR AND WILLIAM G. COCHRAN, STATISTICAL METHODS, 8th Ed. (Ames, Iowa: Iowa State University Press, 1989).

5. For a discussion of value-at-risk, see JOHN C. HULL, OPTIONS, FUTURES, AND OTHER DERIVATIVES, 4th Ed. (Upper Saddle River, NJ: Prentice-Hall, 1999), Chapter 14.

6. For a description of dynamic programming, see Dixit and Pindyck, *supra* note 3.

7. For a discussion of stochastic dominance and its application to resource planning, see Jonathan A. Lesser, *Application of Stochastic Dominance Tests to Utility Resource Planning Under Uncertainty*, ENERGY, Dec. 1990, at 949–961.

8. Separate concurring opinion of Justice Brandeis, *Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission*, 262 U.S. 276 (1923).

9. National Regulatory Research Institute, *The Prudent Investment Test in the 1980s*, Apr. 1985, at iv.

10. *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 309 (1989).

11. *Denver Union Stock Yard v. United States*, 304 U.S. 470, 475 (1938).

12. *Market Street Ry. v. California R.R. Comm'n*. 324 U.S. 548 (1945).