Synapse
Energy Economics, Inc.

Portfolio Management:

How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers

Prepared by:
Bruce Biewald, Tim Woolf, Amy Roschelle, and William Steinhurst
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

Prepared for:
The Regulatory Assistance Project and The Energy Foundation

October 10, 2003

Table of Contents

List of Tables

List of Figures

Acknowledgments

The authors would like to thank Regulatory Assistance Project and the Energy Foundation for providing the funding for this report. We would also like to thank the following individuals for their invaluable comments on drafts of this report.

Barbara Alexander

Joe Cavicci, Lexecon Consulting

Cheryl Harrington, Regulatory Assistance Project

Jim Lazar, Regulatory Assistance Project

David Moskovitz, Regulatory Assistance Project

Jerry Oppenheim

Richard Rosen, Tellus Institute

Richard Sedano, Regulatory Assistance Project

Mark Thompson

Rick Weston, Regulatory Assistance Project

David Wooley, Energy Foundation

Ken Zimmerman, Chief of Accounting and Financial Analysis, Public Utility Division, Oklahoma Corporation Commission

Executive Summary

A Brief Description of Portfolio Management

Portfolio management offers electric utilities and their regulators a process for making the most of the rapid changes and developments in today's electricity markets. A utility or default service provider that actively participates in electricity markets, and that carefully chooses among the wide variety of different electricity products and resources, will be able to provide better services to its customers over both the short- and long-term future.

Portfolio management begins with the primary objectives of a utility or default service provider in obtaining electricity resources for customers. Providing reliable electricity services at just and reasonable rates will continue to be a primary goal of electric utilities. Other objectives include mitigating risk; maintaining customer equity; improving the efficiency of the generation, transmission and distribution system; improving the efficiency of customer end-use consumption, and reduction of environmental impacts. Portfolio management provides a process for utilities to determine and implement the mix of electricity resources that will achieve these objectives to the greatest extent possible.

Portfolio management requires several key steps on the part of electric utilities or default service providers. Portfolio managers must first prepare load forecasts that represent the best assessment of customer demands for generation, transmission and distribution services for the long-term future. They must then assess all the opportunities available for meeting customer demand through cost-effective energy efficiency resources. The next step includes assessing the wide variety of generation-related opportunities, including building power plants; purchasing from the wholesale spot market; purchasing short-term and long-term forward contracts; purchasing derivatives to hedge against risk; developing distributed generation options; building or purchasing renewable resources; and expanding transmission and distribution facilities. The next, and most challenging, step in portfolio management is to develop the optimal mix of these resources that will best achieve various objectives identified by the utility and promoted by the regulators.

With the current lack of retail competition, default service providers have little pressure or incentive to pass the benefits of their long-term portfolios on to retail customers. State policymakers need to create the necessary conditions for the full benefits of successful portfolio management to flow to retail electric customers. It may also be that some default service providers only *passively* participate in the competitive electric market, by purchasing all of their generation from relatively short-term options. In so doing, they are missing many opportunities, and they are leaving their customers vulnerable to higher costs and greater risks. In order to benefit from competitive electricity markets, default service providers must participate more *actively* in procuring resources for their customers.

Portfolio management is also important for those utilities that remain vertically integrated. It provides a means for these utilities to meet the traditional objectives of providing reliable, low-cost electricity services by taking advantage of the new and emerging opportunities available from the competitive wholesale electricity markets.

The Benefits of Portfolio Management

In jurisdictions where retail competition has been introduced, the vast majority of customers continue to be served by the default service provider. This trend is likely to continue well into the foreseeable future, as a result of the many barriers that limit customers' ability to switch to alternative generation companies. Portfolio management provides a means for these customers to enjoy some of the benefits offered by the competitive wholesale markets, through the efforts of the portfolio manager who essentially acts as their "broker."

If done well, portfolio management will result in lower electricity costs, lower electricity bills, and more stable electricity prices. If, instead, default service providers are allowed to simply pass the costs of short-term generation contracts to customer, customers will be subject to higher electricity prices, greater volatility in prices, and greater risks of future cost increases.

Portfolio management will also improve the operations and the competitiveness of the wholesale electricity markets. By representing large volumes of customers, and by increasing the demand for a more diverse range of competitive options (e.g., a variety of forward contracts), portfolio management will result in a more robust wholesale market, and will limit the ability of a few key generation companies to manipulate the market through the predominance of short-term contracts and spot market purchases. In sum, portfolio management is not only consistent with competitive markets; it is, in fact, necessary to ensure that competitive wholesale markets are robust.

Regulators will also benefit from portfolio management, as it provides them with an opportunity to ensure that all customers continue to be provided with the best possible electric services available. Portfolio management is also one of the few policy tools available that allows regulators to simultaneously promote competitive wholesale electricity markets and protect consumers from some of the risks of competitive markets.

Portfolio management also offers other advantages to customers, regulators and utilities. It can reduce the risk of price volatility and of future price increases through the promotion of diverse resource types. It can help improve reliability by promoting smaller, modular resources, and by slowing down load growth. It can also promote the more efficient use of electricity resources, improvements in the utilization of transmission and distribution facilities, and increased use of renewable and distributed generation resources.

Demand Forecasts: Must Assess the Impacts of Customer Choice

Load forecasts play an essential role in portfolio management, as they provide the foundation for making decisions about the need for new electric resources. Load forecasting techniques are by now well-established in the electric utility industry. However, electricity industry restructuring and portfolio management raise several new issues for utilities and regulators to consider.

- Regulators should require utilities to provide descriptions and documentation of their load forecasts as part of their portfolio management obligations.
- Utilities in states with retail electricity competition should be required to prepare and present separate load forecasts for transmission and distribution (T&D) services and for default generation services.
- The forecast of demand for default service must include a comprehensive assessment of the competitive electricity market over the short-, medium- and long-term future, in order to assess the extent to which customers are likely to switch providers.
- The forecast of default service demand must include a detailed estimate of future default service customer retention rates, by customer class.
- In competitive markets, the forecasts of demand for default service should include a broader range of sensitivities than typically used by a vertically-integrated utility.

Finally, as the roles for providing default and competitive generation services become spread across more than one entity (competitive generators, distribution utility, other default service providers, etc.), it will be important for regulators to clarify who has responsibility for making comprehensive load forecasts.

Energy Efficiency: Still a Cost-Effective Resource Option

Throughout the United States, there is a large potential for energy efficiency measures that reduce customer demand but cost significantly less than generating, transmitting and distributing electricity. Energy efficiency programs offer enormous opportunities for lowering system-wide electricity costs and reducing customers' electricity bills. They also offer other important benefits in terms of reducing risk, improving reliability, mitigating peak demands, mitigating environmental impacts, and promoting economic development.

Despite widespread scaling back of utility energy efficiency programs during the 1990s, the primary rationale for implementing energy efficiency programs – to reduce electricity costs and lower customer bills – is just as relevant in today's electricity industry as it has been in the past. Consequently, energy efficiency is an important resource to include in portfolio management, because it can (a) lower electricity costs and customers' bill, and (b) reduce the amount of generation needed to be obtained from the market.

Some states have established a system benefits charge (SBC). A fixed charge is collected from all distribution customers to provide stable base funding for energy efficiency activities and to address some of the concerns created by restructuring. However, SBCs in place today fall far short of capturing the full potential for cost-effective energy efficiency to meet the future needs of the system and consumers. Consequently, portfolio management should be used to identify and implement additional energy efficiency beyond that which is implemented through SBCs.

The methodologies and tools for assessing and selecting cost-effective energy efficiency resources are by now well-established. In general, efficiency programs should be implemented if their total life-cycle costs are lower than those of comparable generation, transmission and distribution facilities. The Rate Impact Measure test, representing a narrow and short term perspective, should not be used as the primary criterion for screening energy efficiency resources. Instead, rate impact concerns should be addressed through proper program design and budgeting.

Generation Resources: A Variety of Opportunities

Portfolio management requires that utilities and default service providers take advantage of all the electricity generation, and generation-related, opportunities that are available in today's electricity markets, including:

- *Building and operating a new power plant*. Within this category there are many technology and fuel types to consider, each with important planning considerations such as capital costs, financing requirements, fuel costs, construction lead time, compliance with environmental regulations, siting and permitting, and more.
- *Purchases from the wholesale spot market*. These offer the advantage of no long-term commitment and flexible response to customer demand, but the disadvantage of being highly volatile and subject to market risk.
- *Short-, medium-, and long-term contracts for power*. Forward contracts avoid exposure to spot market volatility and can reduce costs, but mean that buyers cannot take advantage of falling market prices if they occur and incur the risk that the counter-party may default, or that demand may fall.
- *Option contracts and flexibility contracts*. These contracts provide greater certainty than forward contracts but may result in additional transaction and pricing costs.
- *Financial derivatives such as futures contracts and swaps*. These provide the buyers with financial hedge against future price spikes. The goal of derivatives is to stabilize prices, but not necessarily lower them.
- *Distributed generation facilities*. These are small, modular generation technologies that can be installed in particular locations on the power grid where generation is especially valuable, including a customer's premises.

In addition, there are a variety of ways that the actual purchasing of these resources can be implemented in order to get the best deal for customers. For example, "dollar cost averaging" is a technique whereby purchases of a commodity are made in small increments at frequent durations (e.g., 12 monthly purchases instead of a single yearly purchase), in order to mitigate the effects of price fluctuations and spikes.

It is important for utilities and portfolio managers to consider many factors in comparing these different generation-related opportunities. For example, physical hedges (such as building or buying renewable resources to hedge against gas price risk) are likely to be more reliable and safer than financial hedges (such as gas fixed price gas contracts or gas price futures), because the latter are only available for relatively short time periods and are subject to default, bankruptcies and forced renegotiation from the seller.

Transmission and Distribution: Integrate Into the Resource Plan

Portfolio management also requires that utilities and default service providers consider transmission and distribution opportunities and costs in developing the resource portfolio. Decisions regarding the maintenance or enhancement of T&D facilities will have important consequences for the development of generation and efficiency resources, and vice versa.

Portfolio managers should consider not only the generation resources that are available with the existing transmission system, but also those that could be tapped via new or upgraded transmission. Similarly, evaluation of generation resources should reflect the costs, engineering and permitting requirements and impacts of transmission required to bring the power to consumers.

Conversely, portfolio managers should also consider whether costly T&D upgrades and enhancements can be deferred or avoided through strategic placement of power plants, energy efficiency investments or distributed generation technologies. The interplay between T&D investments and alternative resource options will have important implications for the T&D portions of customers' bills as well as the generation portion.

Determining the Optimal Resource Portfolio: Putting It All Together

The most important aspect of portfolio management is in determining the optimal combination of resources to meet customers' needs. At this point in the portfolio management process, all of the analyses described above are pulled together to identify the preferred resource portfolio.

Portfolio managers should clarify their objectives, and use these as selection criteria for making decisions between competing resource options. The primary objectives should include: (a) maintain low cost of electricity; (b) provide safe and reliable electricity service; (c) maintain stable electricity prices over the short- and long-term; (d) mitigate risk, both in terms of price volatility and price increases; (e) utilize resources efficiently, at the customer end-use, and at generation, transmission and distribution facilities; (f) mitigate environmental impacts of electricity services; and (g) maintain a flexible portfolio, able to respond to market and industry changes.

Resource portfolios should be prepared to cover the long-term planning horizon (e.g., 20 years), in order to capture the full range of opportunities, benefits and costs associated with resource decisions. Determining the optimal resource portfolio requires several steps:

- Determine a set of generation options that would best be able to meet the expected customer demand. This should be based on a comprehensive assessment of conventional power plants, renewable resources, spot market purchases, and short-, medium-, and long-term power contracts.
- Assess opportunities for transmission and distribution upgrades and enhancements to improve the mix of generation options. Similarly, assess opportunities for different mixes of generation options to reduce T&D costs or improve T&D

opportunities. Distributed generation options should be factored into this assessment.

- Determine the set of energy efficiency programs that would reduce demand and reduce the costs of the generation, transmission and distribution options selected so far. The potential for "demand response" to reduce costs during peak periods is also considered at this point. All efficiency measures and programs that can reduce the total cost of electricity should be integrated into the resource plan.
- Conduct risk analyses to assess the extent to which the resource portfolio is subject to short-term and long-term risks. This includes anticipating key potential deviations from the assumptions and forecasts used, and assessing the sensitivity of the resource portfolio to potential uncertainties.
- Determine the set of financial hedging instruments that would help mitigate the key risks that might remain in the resource portfolio. The optimal resource portfolio should strike the appropriate balance between reducing costs and reducing risks.

The portfolio manager may need to iterate a portfolio through these steps several times in order to fully assess the inter-related effects of the different resource types. Another approach is to develop several alternative resource plans, and assess how each of them meets the planning objectives and criteria. Smaller default service providers, with less expertise and resources, may simplify some of these steps, but each step is important in the portfolio management process.

Default service providers in jurisdictions where retail competition is allowed will have greater uncertainty regarding customer demand for generation services and thus should analyze several different scenarios for customer demand. An optimal resource portfolio should be determined for each of the different demand scenarios, and each portfolio should be flexible enough to respond to changing demand over time.

Maintaining an Optimal Portfolio over Time: Vigilance and Flexibility

Once an optimal resource plan has been determined, the portfolio manager must implement the plan flexibly and judiciously over time. Ongoing evaluation and updating will not only help realize the full potential of PM and risk management, but will also allow portfolio managers to respond to unexpected developments in wholesale electricity markets and the industry in general.

To ensure that the portfolio strategy is successfully implemented, an action plan should be prepared that covers (a) acquisition and disposal of portfolio elements; (b) monitoring of market conditions, environmental trends, and electric loads; (c) monitoring of portfolio performance; and (d) evaluation of potential new acquisitions or hedging instruments. Counterparty credit and settlement risk require constant attention. Both supply and demand side initiatives should be evaluated on a regular basis.

Regulatory and Policy Issues: Clear Guidance and Incentives

Legislators, regulators and other stakeholders will have to play a key role in portfolio management in order for it to be successful. First and foremost, legislators and regulators must make it clear that all utilities and default service providers must actively and aggressively pursue all opportunities to reduce costs, mitigate risks, and achieve other key public policy goals.

Regulators should require utilities to submit periodic (e.g., every two years) portfolio management plans and progress reports that describe in detail the assumptions used, the opportunities assessed, and the decisions made in developing their resource portfolios. Regulators should carefully review these plans and either approve them or reject them with recommendations for modifications necessary for approval.

Finally, regulators should establish regulatory and ratemaking policies that provide utilities with the appropriate financial incentives to prepare and implement proper resource portfolios. This includes incentives to (a) design and implement cost-effective efficiency programs; (b) develop cost-effective distributed generation options; (c) identify and implement the optimal mix of power plants and purchase contracts; (d) implement risk management techniques; and (e) implement, update, and modify the resource plan over time in order to respond to changing market and industry conditions.

1. Introduction

Overview of Portfolio Management

Providing good retail electric service in today's electricity industry is challenging due to volatile wholesale market prices, fuel supply risks, market power considerations, uncertainty about environmental impacts and regulations, and bankruptcy filings by major players. In situations with retail electricity restructuring, there are additional challenges associated with the possibility of customer switching.

Portfolio management (PM), both as a theory and a practical reality, has been successfully applied in a wide range of industries to procure resources and manage risks. Portfolio management as applied to the electricity industry is based on the simple notion that a utility or default service provider that actively participates in electricity markets, and that carefully chooses among the wide variety of different electricity products and resources, will be able to provide better services to their customers over both the short- and long-term future.

Portfolio management requires several key steps on the part of electric utilities or default service providers:

- Portfolio management begins with the regulators, utilities and other stakeholders identifying the primary objectives that should be used in obtaining electricity resources to meet customers' needs.
- Portfolio managers must prepare load forecasts that represent the best assessment of customer demands for generation, transmission and distribution services for the long-term future.
- They must then assess all the opportunities available for meeting customer demand through cost-effective energy efficiency resources.
- The next step includes assessing the wide variety of generation-related opportunities, including building power plants; purchasing from the wholesale spot market; purchasing short-term and long-term forward contracts; purchasing derivatives to hedge against risk; developing distributed generation options; building or purchasing renewable resources; and expanding transmission and distribution facilities.
- The next step in portfolio management is to develop the optimal mix of these resources that will best achieve the various objectives. A sound portfolio management approach will seek to adopt a variety of resource types to lower costs, reduce risk, and achieve other key objectives.
- Finally, utilities and default service providers must constantly upgrade and modify their resource portfolios and acquisition plans in order to respond to industry changes over time.

Outline of this Report

This report provides regulators, utilities, or other parties that have a stake in the provision of electric generation with theoretical and practical concepts and methods for managing the procurement of electricity resources through portfolio management. We hope that this report will be used as a reference document to assist with the understanding and application of portfolio management techniques. The list below provides a general guide for the various topics covered.

The need for portfolio management. Chapter 2 provides the rationale for implementing portfolio management, either in jurisdictions with retail competition or in those without. It also defines the term "default service provider," and discusses the volatile nature of prices in today's wholesale electricity markets.

The benefits of portfolio management. Chapter 3 presents some of the key benefits of portfolio management, including the regulatory benefits, the ability to mitigate risks, the ability to promote more efficient and robust wholesale electric markets, and the ability to improve system reliability.

Portfolio management concepts. Chapter 4 presents some of the key portfolio management concepts that can be applied in any industry, along with examples of how these general concepts can be applied in the electricity industry. It also provides a brief discussion of some of the portfolio management practices that are being applied in the electricity industry today, both in states with and without retail competition.

Forecasting electricity demand. Chapter 5 discusses the role of demand forecasting in portfolio management, and explains how default service providers must develop forecasts of the demand for generation services despite the uncertainty introduced by retail competition.

Options for managing electricity demand. Chapter 6 discusses the benefits of energy efficiency, and the role energy efficiency must play in portfolio management. It explains how portfolio managers should consider energy efficiency resources above those required through system benefits charges, and how the rate impacts of energy efficiency programs should be addressed.

Generation options. Chapter 7 presents an overview of the many types of generation options available today, including different technology types, different ownership/purchase arrangements, and distributed generation options. It also discusses different types of power contracts, financial hedging instruments, and how to balance long-term versus short-term options.

Transmission and distribution options. Chapter 8 discusses the role that transmission and distribution facilities should play in portfolio management, and the relationship between T&D, generation and efficiency resources.

Determining the optimal resource portfolio. Chapter 9 describes some of the concepts used to select among the many resource options in order to meet the primary objectives of portfolio management, and lists several techniques for analyzing risk exposure.

Maintaining an optimal resource portfolio. Chapter 10 explains why and how a portfolio manager should upgrade and modify their resource portfolios and acquisition plans in order to respond to industry changes over time

Regulatory and policy issues. Chapter 11 presents some of the regulatory and policy issues that will need to be addressed in order to support the implementation of portfolio management. The objective of this Chapter is to only raise the key regulatory issues; it does not provide a detailed description of the policies necessary to make portfolio management happen. Such policies should be the subject of further research.

2. The Need for Portfolio Management in Today's Electricity Markets

Nationally, electricity markets are undergoing extraordinarily rapid change. For the first time, states need to develop ways to protect retail electric customers from price fluctuations found in competitive markets.

States that have introduced retail electricity competition have typically established "default service providers" to ensure that all customers have uninterrupted, reliable access to electricity generation services. Many legislators and regulators originally expected that over time most customers would switch to competitive generation providers, and that the default services would only be needed either as a transitional mechanism, or as a means of serving only a small number of customers. As such, less attention was paid to the requirements for providing default services, and the policies associated with default service providers.

What Is a Default Service Provider?

Jurisdictions that allow retail competition have typically established a "default service provider" who delivers *generation service* (as distinct from *transmission and distribution services*) for any customer who, for whatever reason, does not have a competitive retail provider. The default service is sometimes referred to as "standard offer," and the default service provider is sometimes referred to as the "provider of last resort."

In many states, the default service provider is the remaining distribution utility. Sometimes it is a competitively-selected entity functioning in a manner similar to competitive generation companies. In jurisdictions without retail choice, or in which not all customer groups have retail choice, the incumbent vertically-integrated electric utility typically continues to provide monopoly *generation service*, along with transmission and distribution services.

This report uses the term *default services* to mean generation service provided to customers who do not have access to retail choice for any reason, including lack of retail competition. A *default service provider* is whatever entity provides that default service.[1]

However, in most states that have established retail competition the vast majority of customers continue to be served by the default service provider. (Alexander 2002) This is due to many reasons, including limited generation options, lack of customer information, lack of customer interest, uncertainties associated with restructured electricity markets, and transaction costs associated with switching.

It is quite likely that the majority of customers, especially residential, and small commercial and industrial customers, will continue to require default services well into

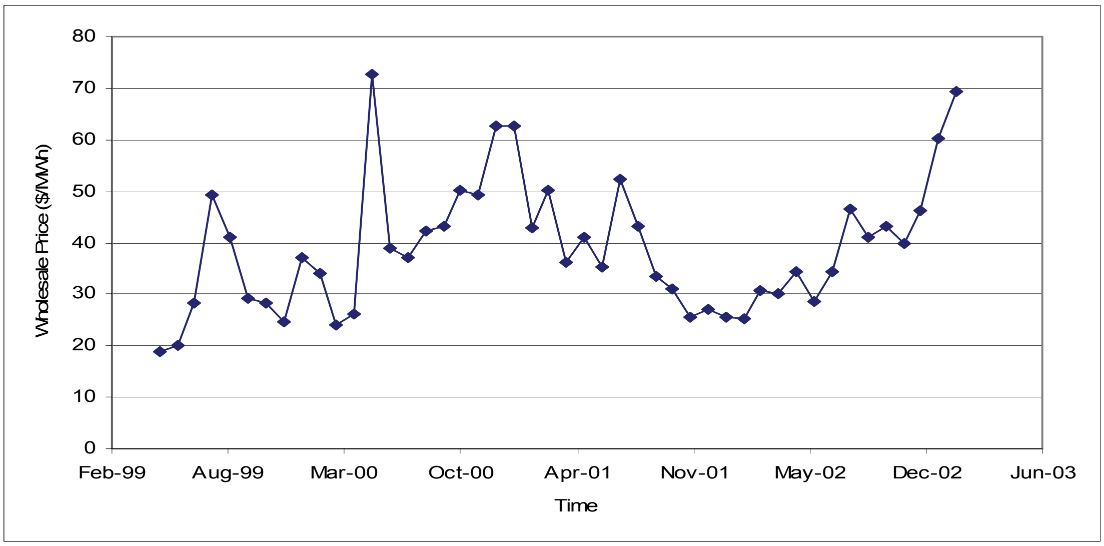
---

[1] Some jurisdictions that established retail choice offered a *transitional default service* for a limited time or with limited eligibility. This report does not explicitly discuss such transitional default services. However, regulators should consider whether and how to apply PM principles to transitional default services, where they exist.

the foreseeable future. Legislators and regulators can play an essential role in ensuring that these customers are provided with reliable, low-cost electricity services at stable prices in the near-term and over the long run. (Harrington, et al. 2002) Portfolio management offers the tools and techniques to achieve this important goal.

For example, recent procurement practices, particularly in areas with retail choice, overemphasize relatively short-term contracts. Many default service providers simply establish new generation contracts for short-term power every six or twelve months. This exposes customers (or providers, depending on how each jurisdiction allocates market risk) to costs based on whatever happens to be the state of the market on a particular date each year or half-year, with the forward cost of power very strongly influenced by the level of spot market prices at the time.

Figure 2.1. Wholesale Electricity Prices in New England



For example, the wholesale electricity prices in New England have fluctuated dramatically in recent years, as indicated in Figure 2.1. If a default service provider were to purchase all of its generation through a short-term contract at the time of one of the peak wholesale prices, then its customers would end up paying considerably more for electricity than necessary.

In recent years, those states relying upon short-term wholesale market prices for default services (e.g., Massachusetts, New York, Texas) have experienced higher costs and greater price volatility than other states with default services. (Alexander 2002) Portfolio management offers a way to mitigate against higher costs and price volatility.

Portfolio management practices can also benefit providers and customers in jurisdictions that have not introduced retail choice. Portfolio management can be used by vertically-integrated utilities to protect themselves (without undue transfer of risk to consumers) from uncertainties in wholesale markets, transmission congestion costs, environmental compliance costs, credit risks, fuel price risk, and ancillary service costs. Thus, in all states, restructured or not, portfolio management is a way to deal with the evolving developments, uncertainties, and volatilities in the electricity industry.

This report concerns itself with portfolio management issues and techniques from the perspective of a single electric utility or, at most, a single state. That is, we address here the question of why regulators should ensure that sound portfolio management practices prevail in the acquisition of electricity resources for both monopoly service customers and default service customers under retail choice. The same benefits and techniques are applicable at other geographic resolutions. Entire power pools, Independent System Operators, and Regional Transmission Organizations can and should consider how to take advantage of portfolio management or, perhaps more importantly, how to facilitate the harvesting of portfolio management benefits by their load serving entities. At the other end of the scale, cities and sub-state regions are beginning to recognize the importance of electric energy availability, price risks, and environmental risks to their interests. This has led to concerted energy planning efforts by cities and other government entities not ordinarily concerned with utility regulation. (BED 2003; SF 2002) While this report does not specifically address either of those ends of the geographic spectrum, many of the concepts and principals should translate effectively.

3. Benefits of Portfolio Management

3.1 Portfolio Management Offers Regulatory Benefits

Regulators will benefit from portfolio management, as it provides them with an opportunity to ensure all customers continue to be provided with the best possible electric services available. In states that allow retail competition, portfolio management is one of the few regulatory tools available to protect customers from some of the risks of competitive markets, and to ensure that customers are provided just and reasonable rates.

Portfolio management also offers a way to shift the electric utilities' focus from short-term, market-driven prices to long-term customer costs and customer bills. This shift allows regulators to maintain (or reintroduce) key public policy goals into the critical function of power procurement for the large majority of electricity customers. Portfolio management offers regulators a mechanism to promote energy efficiency, build markets for renewable generation, encourage fuel and technology diversity, and achieve environmental objectives.

3.2 Portfolio Management Can Reduce Many Types of Risks

Under traditional rate regulation, retail ratepayers saw a cost of power (generation service, exclusive of T&D and G&A) determined in large part by the embedded capital cost of owned power plants and by purchased power contracts with fixed or largely fixed prices. Some fraction of the cost of power from those resources was driven by fuel prices. Those fuel prices were, in turn, set by volatile markets, but most utilities engaged in some form of hedging for fuel purchasing and any fuel cost savings from hedged purchases (or inherently low-cost fuels like coal) largely flowed through to customers. Any modest excess or shortfall of power was dealt with in trades between rate-regulated utilities, often under "split the savings" arrangements that benefited the rate payers of both the selling and buying utilities.

More recently, many wholesale power markets have moved to a structure in which *all* power generated in a given hour is offered into a bid-based spot market in which the clearing price set by the *most expensive* source, typically natural gas-fired power. This has introduced immense volatility into spot prices. Simultaneously, some jurisdictions required default providers to divest themselves of plant ownership and long term hedging contracts, thereby exacerbating utilities' reliance upon spot markets and short-term contracts. While the vertical market power concerns that led to such constraints may have been important, the result was often catastrophic for the provider or the consumer. (Harrington, et al., 2002; Alexander 2003)

Fortunately, PM practices can help to reduce risk exposure and reclaim some of the cost efficiencies that were discarded with the adoption of a "merchant generation and spot market" approach to electricity. Some of the key risks facing the electricity industry are briefly discussed below.

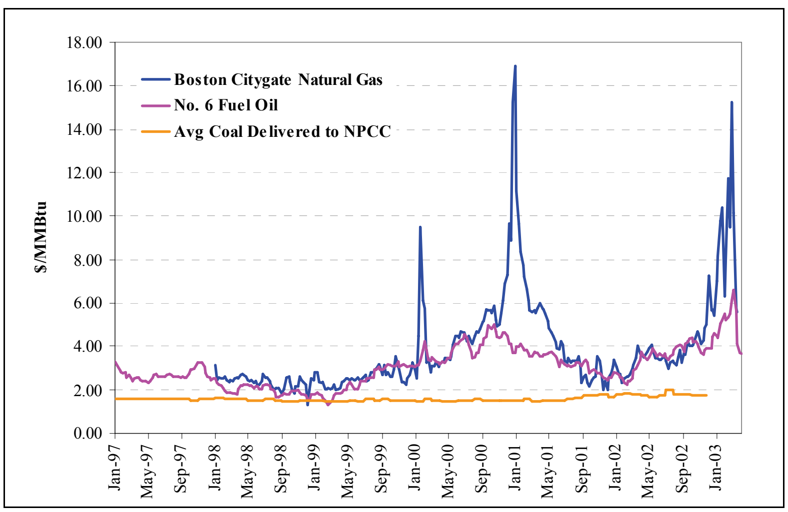
Risks Due to Gas Prices and Supply

> "Average U.S. peak electricity prices are expected to rise 48 percent in 2003 from the previous year, mostly the result of a surge in natural gas prices… We do not forecast a return to normal supply- demand balance… before 2008." (UBS 2003)

Increasingly, many regions of the United States are relying on natural gas to generate electricity. As a result, wholesale electricity prices are directly linked to natural gas prices, which have been highly volatile in recent years relative to other fuels. While the resource base for natural gas remains large, increased production will require massive investments and time. For instance, in Atlantic Canada, major new supply is unlikely to materialize before the end of 2008. It is anticipated that such investments will be linked to higher commodity prices, increased price volatility, and larger trading volumes. Thus, it seems gas price volatility and, hence, electricity price volatility is here to stay until new gas supplies are commercialized in future years. (Levitan & Associates, Inc. 2003)

In the New England region, gas as a fuel source for electricity has been increasing markedly. In 1999, gas-fired generation represented 16% of all electricity in the region. In 2003, this number increased to 41%. It is expected that use of natural gas to generate electricity will total 49% in New England by 2010. Other than the state of Texas, New England is the most gas-dependent region in North America for power generation. Interestingly, gas-fired units set over 50% of all electricity prices in New England. As indicated in Figure 3.1 natural gas prices have been highly volatile in recent years, and are have been much more volatile than other fuels such as coal or fuel oil.

Figure 3.1. Comparative Fuel Costs Delivered to New England.



Source: ISO New England, 2003

Risks Due to Future Environmental Regulations

Compliance with federal and state environmental regulations can be costly. And there is considerable uncertainty about the type and extent of environmental regulations that may be imposed in the near- to long-term future. While it is difficult for utilities and default service providers to predict the full impact of future environmental regulations, planning for such uncertainties and hedging against those risks is feasible and vital.

Quantifying Regulatory Risk

PacifiCorp has estimated that the cost of meeting present, pending and future SO2, NOx, and Hg regulations will be substantial, with related after-tax O&M, A&G and capital expenditures through 2025 ranging between $500 million to $1.7 billion (NPV). The lower figure represents an SO2 scrubber and low NOx burners scenario. The higher amount represents full controls (SO2 scrubbers, Selective Catalytic Reduction controls for NOx, and bag houses with activated carbon injection for mercury). (PacifiCorp 2003)

Utilities already must comply with sulfur dioxide (SO2) and nitrous oxides (NOx) emission requirements; most utilities recognize that CO2 regulation in some form is highly likely. Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level, the most important being:

- President Bush's Clear Skies Act/Global Climate Change Initiatives.[2]
- The Clean Air Planning Act of 2002 introduced by Senators Carper and Lincoln.[3]
- The Clean Power Act introduced by Senator Jeffords.[4]

To protect themselves against the risk of such future regulations, utilities can diversify by investing in generating assets with a mix of emissions profiles. For example, utility companies might acquire or build wind farms or convert from coal to gas-fired plants, rounding out their portfolio to include more environmental- and regulation-friendly assets. Portfolio management offers regulators, utilities and default service providers the tools necessary to develop a diverse set of electricity resources.

Similarly, energy efficiency and demand-side management programs also provide significant hedging value against environmental risks. Demand-side hedging programs are by no means unique to the electric industry. Liability insurers not only hedge their payout risks by re-insuring those risks, but engage in both customer specific education and technical assistance and generic programs (such as establishing the Underwriters'

2 The Clear Skies Act would require reductions for SO2, NOx, and mercury (Hg) in two phases (2008 and 2019) with tradable allowances. The proposal addresses the different air quality issues across the county and would set emission caps to account for these differences. The Global Climate Change Initiative is a voluntary greenhouse gas (GHG) reduction program. It focuses on improving the carbon efficiency of the economy, reducing current emissions of 183 metric tons per million dollars of GDP to 151 metric tons per million dollars of GDP by 2012. The program encourages generators of CO2, including power plants, to reduce emissions.

3 The Clean Air Planning Act would regulate SO2, NOx, Hg, and CO2 emissions from the electric generating sector: (1) the SO2 mandate would reduce emissions over three phases to 2.25 million tons in 2015; (2) the 2-phase NOx program culminates with a 2012 cap of 1.7 million tons; (3) the mercury cap would be in two phases, 2008 and 2012; and (4) the two-phase CO2 program would cap emissions at 2005 levels in 2008 and 2001 levels in 2012.

4 The Jeffords bill would require power plants to reduce SO2 and NOx emissions by 75 percent, mercury emissions by 90 percent, and carbon dioxide to 1990 levels, all by 2008.

Laboratory) to reduce those payouts. Airlines and cellular communications companies engage in peak shaving rate designs, as do many restaurants (in the guise of early bird discounts).

> **Hedging Environmental Regulatory Risk**
>
> Cinergy Corporation provides electrical power to about two million customers in Ohio, Indiana, and Kentucky. Ninety percent of the electricity it produces comes from its coal-powered plants, which release as much as 70 million tons of CO_2 annually. Cinergy's CEO has publicly stated his belief that energy companies should reduce emissions or at least avoid increases. Cinergy has spent $1 billion to convert a coal-fired plant to natural gas, which emits about one-third the carbon dioxide per MWh generated, and to buy two gas-fired plants. It has also experimented with windmills and fuel cells. Cinergy has recently announced a commitment to reduce its carbon dioxide emissions by 5 percent by 2010 (Boyer 2003). By managing its carbon emissions Cinergy is hedging against future environmental regulation risk. (Cortese 2003)

3.3 Portfolio Management Promotes More Efficient Markets

Wholesale markets for electricity have fallen short of the ideal of perfectly competitive and efficient markets. Severe market power problems have occurred and may continue to occur in various markets.[5]

Portfolio management can reduce retail customers' exposure to wholesale market power, and even reduce the extent to which market power is a problem in those wholesale markets. For example, PM encourages default service providers to mix short- and long-term wholesale power contracts to manage commodity supply and price risk. This action also limits the extent to which large players in the spot market can profitably exercise market power through strategic withholding, fostering more stable competitive markets for both the short-term and the long-term. "The use of portfolio management may be the greatest leverage state regulators have to influence the actual operations of wholesale markets." (Harrington, et al., 2002, 7 ff.; Cavanagh 2001)

Furthermore, not all types of fuels and technologies are equally able to enter the markets. Renewable technologies are often more capital intensive than fossil fuel technologies and also face information and capital access barriers that prevent them obtaining financing if their only potential for revenue comes from competing in spot markets or selling under short term contracts. PM can properly value the hedging benefits of such technologies and of energy efficiency, increasing the competitiveness and efficiency of wholesale power markets.

---

[5] For the nature of such threats and their importance, see, Trebing 1998. For the reality of the problems, one need only consult the electric industry trade press anytime in the past five years. Perhaps the ultimate form of market power faced in assembling a default service portfolio is the situation where an affiliate of the default service provider is able to capture the role of seller to that provider. Here, long - term contracts and even plant ownership or resource-based contracts are no solution. Comparisons to short-term or spot pricing may be helpful in monitoring or mitigating such power, but only strong codes of conduct and affiliate transaction rules, coupled with clear PM guidance and expectations can hope to adequately protect consumers in such a situation. (Burns, et al., 1999, p. 19)

3.4 Portfolio Management Can Improve System Reliability

PM can not only reduce price volatility and mitigate market power, but also offers significant reliability benefits. Reliability benefits should be a factor in valuing portfolio alternatives. Smaller units, varied technology types and fuels, and other factors can reduce the exposure to system outages and the cost of avoiding those outages.

Diversification among Smaller Resources

Sound application of PM should lead to diversification of electricity resources, suppliers, and contract types and terms. Diversification can take the form of varied fuels, technologies and a mix of generation, transmission and demand-side resources. On average, each particular resource will be a relatively smaller proportion of the resource mix than if diversification were not pursued. Relying on a large number of small resources is inherently more reliable than a portfolio made up of one or a few resources subject to unique risks.[6]

The cost of providing adequate system reserves in a control region is affected by the choice and size of the generating resources in that region. Reserves and operating requirements for both loss of load and system stability contingencies (for example, installed capacity margins and spinning reserves, respectively) are often driven by the largest single potential outage that could occur on the system, typically a large power plant or transmission line tripping out. Therefore, a portfolio of smaller, more dispersed resources, both supply- and demand-side, has the potential to reduce the cost of reliability for all market participants.

Readily dispatchable demand-side resources such as interruptible cooling loads can reduce the amount of reserves needed, while saving the fuel cost of keeping a spinning reserve unit operating in an unloaded mode. The availability of demand-response can also lead to more efficient system dispatch and provision of operating reserves, with associated benefits in the form of reduced system fuel costs and air emissions (Keith, et al., 2003).

Diversification among Technology and Fuel Types

Different types of fuels are subject to different supply risks. While coal is a domestic and abundant fuel, it has in the past been subject to regional disruption in labor disputes. Natural gas is both inherently volatile in price and dependent on a small number of pipelines for delivery, the failure of which can cause supply shortfalls and additional price volatility. (RAP 2002) A system that relies on stored fuel supplies (either storage of fossil fuel near the unit, or stockpile of coal or biomass) or has short transportation routes

---

[6] Diversification does require the expenditure of management resources and may, in some situations, entail some additional costs over what might be perceived as the least-cost single resource. For example, small generators tend to have higher capital costs per kW than larger units of the same technology (up to a point, but not indefinitely). While not without their own concerns, ownership or contracts for shares of a number of large generating stations can deliver diversification benefits while also tapping into economies of scale.

are less subject to fuel disruption. This variation can be properly valued with portfolio management techniques.[7]

Certain types of technologies can be subject to industry-wide reliability issues. For example, after the TMI nuclear accident, most nuclear power plants in the country were shut down for extended periods for safety upgrades.

Shortening outage recovery times is another important reliability issue. System restart after a wide-spread outage can be a complicated and time-consuming process. Reliance on very large, central station generating plants can further complicate that process. One reason it took so long for the August, 2003, outage in the Eastern United States and Canada to be restored appears to be the fact that a large number of large nuclear and fossil-fired plants tripped off-line at the start of the outage. First, nuclear power plants may have been required to shut down because they require back-up off-site power for critical safety systems. Second, the size, complexity, and impact on the electric grid of large central power stations, both nuclear and fossil-fired, makes bringing them back on-line very challenging technically. Smaller units, and those with more minute-to-minute flexibility in output, are much easier to manage during a system restart. Finally, because the potential damage to a large unit from a trip is significant, operators may be more cautious bringing them back on line than they would be for other types of resources and wait for assurance that there will not be secondary trips.

Wind power is an interesting case in connection with reliability. It is, of course, intermittent, but does add to system reliability, particularly when pooled across a control region with diverse wind regimes. Simulations applying traditional measurement techniques to wind (30% availability) show that they add as much to system reliability as their capacity factor multiplied by their capacity (i.e., 100 MW of wind, with a 30% capacity factor makes the same contribution to system reliability as 33 MW of combustion turbine with a 10% forced outage rate). (Lazar 1993; Bernow, et al., 1994)

Some resources are peak-oriented, and add more to reliability than would necessarily be assumed from typical measures like “availability” or “forced outage” rates. An example would be solar PV, which might have a 35% annual capacity factor, but is most available on hot sunny days when loads are highest in most regions, providing significant hedging against peak price fluctuations. (Awerbuch, 2000)

[7] Diversity across fuel types reduces both supply disruption and price volatility risk. However, it is important not to mistakenly identify substitutable fuels as independent in this regard in resources or markets where different fuels are readily substitutable (e.g., No. 2 fuel oil and natural gas can often be burned in the same generator).

Fixed Price Renewables and Market Peak Prices

Market clearing price savings and volatility reductions can be especially great when fixed-price renewables are added on peak. Photovoltaics will generate the most electricity during midday in the summer season; just when electric load and price is highest for most regions. The importance of peak load shaving is well known, but the value of photovoltaics in reducing load in frequently overlooked. A recent study analyzed the market price of electricity in the PJM region in order to determine the value of generic load reduction. (Marcus and Ruszovan 2002) The estimated value of PV load reduction during the on-peak hours during that summer season was over 27 cents/kWh in the PJM (4.8 times the market price calculated from the regression) and roughly 8.1 cents/kWh during summer mid-peak hours. PV's summer on-peak load reduction value may very well be equal to or exceed the levelized cost of electricity from the panel. This effect is thought to be especially pronounced in unhedged markets.

4. Portfolio Management: Concepts and Practice

4.1 The Basic Idea

This Chapter reviews the key concepts and tools for portfolio management in any industry, and offers a few examples of how it can be applied to electricity industry. Appendix A gives a more extended presentation, along with a discussion of instruments used in non-electric industries.

A basic tenet of financial management is the idea that a diverse portfolio is less risky than any single investment. The same is true for commitments for commodity supply, such as electricity. Because prices of different investments are not perfectly correlated, a decline in the value of one investment is often offset by a rise in the price of the other. When we apply this notion to power supply and efficiency alternatives, we can take advantage of similar variations. Each technology and resource options has its own cost structure and economic drivers. Gas generation has moderate capital costs, but significant fuel costs driven by natural gas prices. Wind energy has high capital costs, but is insensitive to fuel prices. By combining them in appropriate proportions, we can get a mix with a lower, more stable cost than by relying on either alone. (Awerbuch 2000)

Any individual investment or generation alternative has two main sources of risk. The first is *unique risk*, which results from events that are specific to an individual investment or resource. For common stocks, unique factors are those that affect a particular company or sector, such as a mistake or a disaster affecting the company's production or a broader disaster affecting supply of a particular commodity essential to the sector. For generation resources, unique risks include a failure at a specific plant and unexpected regulatory costs affecting a technology.

The other type of risk is *systematic risk*, such as risks due to macroeconomic factors that threaten all investments or power supplies equally. (Culp 2001, 26) With respect to the stock market, these risks include changes in interest rates, exchange rates, real gross national product, inflation, and so on, which affect the price of stock for all companies or all sectors in roughly the same manner. For generation assets, oil and gas shortages or price spikes are examples; recessions or booms that change the demand-supply balance are also types of systematic or market risks.

Equity portfolio managers maintain diversity by investing in a wide range of different companies in different industries. While there are sector-specific funds, these are recognized as riskier than broad-market funds that eliminate unique industry risks through diversification. The manager of an electric resource portfolio would diversify by relying on a variety of different power plants using different fuels and technologies, by using firm power contracts of varying durations and starting dates, and by acquiring a mix of supply- and demand-side resources.

The "take-home message" from the financial markets is that diversification reduces risk or volatility in prices. The unique part of the uncertainty in any individual investment is diversified away when that investment is grouped with others into a portfolio of different investment types and durations. Overall, diversification gives the portfolio manager more flexibility and protection from unknowns. A well-managed portfolio will draw from both demand- and supply-side resources, as well as a mix of short-term, medium-term, and long-term contracts to ensure price protection over time. In addition, if there is owned generation in the portfolio, risk protection will be further enhanced by applying the same portfolio management approaches to fuel acquisition, a technique long practiced in that part of the utility industry.

Whose Ox Will Get Fed? How to Deliver the Benefits of PM to Consumers

Consider the case of the international petroleum company, Exxon. As a portfolio manager, Exxon owns a mix of long-term supplies (owned oil wells) and forward contracts. They sell their product in what is essentially a short-term market. (That is not to say that a firm like Exxon does not engage in forward sales or put options, but that at its *retail* end, its *small end use customers*, especially for gasoline, are buying virtually 100% on the spot market at the gas pump.) It is Exxon that reaps the benefit of its PM efforts, not consumers. In the electricity industry it is essential to find ways to bring the benefits of portfolio management to electric customers.

It is important to remember that risks relate to various time frames. There is the day-to-day and month-to-month volatility of spot market prices for fuels and electricity and their impact on cash flows for utilities and prices for consumers. There are challenges in addressing very long-term risks like the viability of a new technology or the future of world oil markets. In the medium-term, say three to five years, there are numerous risks affecting specific markets, generating facilities, state and regional economies, and the like. Many of the purely financial techniques discussed in this report are particularly suited to managing the shorter-term risks. Others, such as laddering of contracts, can help manage and reduce uncertainty in the mid-term. To address long-term uncertainties, such as major market shifts or new environmental regulations, we need to pay attention to physical resources in the portfolio, as well as the physical resources underlying long-term contracts and markets as a whole, and apply tools like diversification and demand side resources to cope with them.

Finally, we must be careful to not let the focus on risk management be a distraction from the need to minimize total cost of energy service to consumers and society. Portfolio management should be viewed as an enhancement to sound resource planning, not a replacement for it.

Varieties of Procurement Contracts: Pros and Cons

Portfolio management in commodity purchasing is at the forefront of current research at institutions such as MIT's Center for E-business. A well-managed commodity portfolio is usually a combination of many traditional procurement contracts, such as long-term contracts, options and flexibility contracts, and usage of spot markets. Each of these contract types, listed below, has its own pluses and minuses, but in combination they can greatly reduce risk.

- *Spot purchases* involve paying market price on the day that the commodity is needed. Spot market pricing can be quite volatile, but requires no commitments. Spot market reliance protects against both falling demand and falling prices, but exposes the portfolio to risks from rising demand or prices.

- *Forward contracts* are agreements between buyers and suppliers to trade a specific amount of a commodity at a pre-agreed upon price at a given time or times.[8] Payment is on the delivery date. Forward contracts avoid exposure to spot market volatility, but accept the risk that market prices may fall, that the counter-party may default, and that demand may fall.

- In an *option contract*, the buyer prepays a (relatively) small *option fee* up front in return for a commitment from the supplier to reserve a certain quantity of the good for the buyer at a pre-negotiated price called the "strike price." The cost of the option may increase the total price compared to the price (offered at *that time*) of a long-term contract, but one does not need to commit to buying a specific quantity. Typically, the option is *exercised* only when the spot price (on the date of need) exceeds the strike price of the option.

- A *flexibility contract* is like a forward contract, but the amount to be delivered and paid for can differ based on a formula, but by no more than a given percentage determined upon signing the contract. Flexibility contracts are equivalent to a combination of a long-term contract plus an option contract. (Simchi-Leve 2002)

Buyers need to find the optimal trade-off between price and flexibility by an appropriate mix of low price, low flexibility (long-term contracts,) reasonable price but better flexibility (option contracts), or unknown price and supply but no commitment (the spot market.) Varying durations as well as contract types can help.

> **Commodity Hedging for Manufacturing**
>
> Hewlett Packard is perhaps one of the best examples of a company that has gone with the new portfolio contract approach for hedging commodities risk for plastics and other materials. Specifically, in an effort to maximize expected profit while minimizing product cost risks, Hewlett Packard invests in 50% long contracts, 35% option contracts, and leaves 15% of its commodities purchasing needs open to the spot market. (Billington 2002)

Financial Derivatives

So far, we have focused on *physical contracts* (for actual physical delivery of a commodity) between buyers and sellers. Financial derivatives are another kind of

[8] The term or time period of a forward contract can be of whatever length the parties choose and often begins sometime in the future. For example, power contract can be for one month, one year or for the life of a generator and may start immediately on signature, the next month, or one or more years into the future. Forward contracts for less than one year are often called "short-term" contracts, but they are still referred to as "long," as opposed to "spot" purchases.

contract that can have definite advantages as part of a portfolio. Most important, in many markets they are more liquid and have lower transaction costs than physical contracts.[9]

In simplest terms, derivatives may be thought of as side bets on the value of the underlying asset. Like insurance, use of such "hedges" reduces the effect of unknown events in return for a fee. The most common derivatives are futures contracts and swaps.

- *Futures contracts* are advance orders to buy or sell an asset. Like forward physical contracts, the price is fixed at the time of execution, and payment occurs on the delivery day. Unlike forward contracts, futures contracts are highly standardized and traded in huge volumes on futures exchanges, often by speculators as well as physical buyers and sellers. They are readily traded, as profits and losses from these derivative instruments are realized daily under exchange rules.
- A *swap* is a contract that guarantees a fixed price for a commodity over a predetermined period. At the end of each month, the prevailing market settlement price of the commodity is compared to the swap price. If the settlement price is greater than the swap price, the supplier pays the buyer the difference between the settlement price and the swap price. Similarly, if the settlement price is less than the swap price, the buyer pays the supplier the difference. Swaps give price certainty at a cost that is lower than the cost of options, with no physical commodity actually transferred between the buyer and seller.

New types of derivatives and variations on currently used instruments are constantly offered in order to suit a range of investor interests. These include weather derivatives, and a form of swap known as a contract-for-difference.

Derivatives should be viewed as financial insurance instruments that protect the buyer from spikes (and the seller from dips) in commodity pricing. The intent is to stabilize prices, not to lower them.

While derivatives do have their place in commodities risk management, they also have been the objects of scrutiny in a high profile disputes. For example, in 1993, Orange County lost $1.7 billion due to improper use of financial derivatives. Meanwhile, Enron's 2001 bankruptcy, while not caused by derivative use, raised concerns about risk management and transparency of financial information. (EIA 2002)

Price Averaging

Another well-accepted technique is dollar-cost averaging. To dollar-cost average, a buyer will divide necessary purchases into equal dollar amounts at equally spaced time

[9] It is important to keep in mind that there are distinctive requirements that apply to accounting for derivatives under the tax code and under financial accounting standards. These requirements critically impact the financial results of a corporation and must be carefully evaluated and understood to avoid serious legal difficulties. A few scandals aside, these requirements do not impair the beneficial aspects of derivative use, but rather ensure investors, managers and regulators are properly informed. In fact, there are related requirements that apply to financial reporting of commodity contracts, as well. Expert professional advice in these areas is recommended prior to establishing a financial derivatives program.

increments, regardless of price. For example, instead of buying a single forward contract on January 1 for $50 million of product (to be delivered in monthly increments); a buyer may instead purchase $5 million worth of goods every 36.5 days. While some of the contract prices will be higher or lower, based on the market price on the given day of settlement, the math for this technique guarantees that the buyer will acquire more goods when they are inexpensive and less when they are costly. However, instead of price fluctuations, buyers experience fluctuations in volume of goods purchased. As long as the buyer can bear these changes in volumes, dollar-cost averaging is an excellent technique to manage price fluctuation risk.

Laddering

A portfolio made up of only forward contracts can still be diversified to reduce risk. Like a board of directors whose terms are staggered so that a certain fraction expire each year to ensure turnover yet benefit from continuity of management, a portfolio of power supply contracts can be structured so that a modest fraction of the portfolio turns over each year. This laddered approach eliminates both the risk that one will choose a “bad” time to lock in a price for one's entire portfolio and the risk of having to go to market for all of that portfolio in a less than ideal economic environment when a single contract expires. This technique is similar to laddering of bond portfolios for investors; a detailed example of that method is shown in Appendix A.1.

Allocation of Risk between Buyers and Sellers

Derivatives allow buyers to transfer risk to others who could profit from taking the risk. Those taking the risk are called speculators. Speculators play a critical role in derivative markets, as they are willing to assume the risk that the hedger seeks to shed. Some speculators, like insurance companies or brokerage firms, have some advantages in bearing risk. First, due to experience, they may be good at estimating the probability of events and price risks. Second, they may be in a position to provide advice to buyers on how to reduce risk and thus lower their own risks. Third, they can pool risks by holding large, diversified portfolios of agreements, most of which may never seek payments.[10]

There is a fine line between hedging to mitigate volatility and hedging for the purpose of pure speculation to earn profits. Imprudent speculation is undoubtedly an issue of concern for any industry’s participants. It is up to regulators to define this line. Like most regulatory issues, this will likely develop and evolve gradually over time and with experience in specific cases. Some of the portfolio management hedging techniques have had limited and, usually, ad hoc or specialized uses in electric utility planning and regulatory oversight to date, and default service introduces new complications to portfolio management. For these reasons, research is needed to identify the portfolio management tools most suitable for use under various regulatory regimes and to adapt them to the needs of utilities, default service providers and their customers and regulators.

[10] Risk pooling among default providers may be promising, but needs to be further developed as a concept for application in the electricity industry.

Drawing the Line on Speculation

One example of speculation by a regulated utility is the experience of Nevada Power Company during the Western Market crisis in the spring of 2001. Late in 2000, Nevada Power established a procurement strategy with a purchasing target and began buying large amounts of "6x16" blocks of power under forward contracts to meet that target for a time period including the summer of 2001. In February 2001, with forward contracts filling the target, Nevada Power purchased an additional 275 MW of 6x16 power for the third quarter at a price of $419/MWh. In April 2001, at the peak of the market, Nevada Power paid $513/Mwh for another 125 MW of 6x16 power for the third quarter. These two purchases had a total cost of $262 million–but after the Western market prices collapsed in the spring of 2001 this power turned out to have a market value of only $38 million. The Company had procured this power in excess of its needs and was speculating on further increases in market price and the potential for revenues from sales of surplus power. (Biewald 2002) The net loss of more than $200 million was found by the regulators to have been imprudent. (Nevada PUC 2002) Even with the disallowances of these and other costs in Docket 01-11029 and subsequent cases, Nevada consumers have experienced "the highest [rate] increase in the nation over the part 12 years." (Associated Press 2003)

4.2 Portfolio Management in the Electricity Industry Today

Electricity spot market prices demonstrate extreme volatility compared to other commodities, as seen in Table 4.1 below. This volatility is caused by shifts in supply and demand, volatility in fuel prices, and transmission constraints. Some of these shifts are predictable like diurnal usage patterns. However, demand for electricity is also heavily affected by unpredictable and uncontrollable factors like weather and the economy.

Additional, complicating factors include demand surges during summer heat waves, inability to store large quantities of power, the existence of few substitutes, relatively inelastic demand, and market entry barriers, notably high capital costs relative to the marginal production cost.

As a result, it is even more important to apply portfolio management techniques in the electricity industry than in other industries. It is interesting to note that the volatility in electricity spot prices is dramatically greater than in stock and bond markets, where portfolio management techniques are universally-accepted, well-established practices.

Table 4.1. Spot Market Price Volatility for Selected Commodities

Commodity	Average Annual Volatility (Percent) [11]	Market	Period
Electricity			
California-Oregon Border	309.9	Spot-Peak	1996-2001
Cinergy	435.7	Spot-Peak	1996-2001
Palo Verde	304.5	Spot-Peak	1996-2001
PJM	389.1	Spot-Peak	1996-2001
Natural Gas and Petroleum			
Light Sweet Crude Oil, LLS	38.3	Spot	1989-2001
Motor Gasoline, NYH	39.1	Spot	1989-2001
Heating Oil, NYH	38.5	Spot	1989-2001
Natural Gas	78.0	Spot	1992-2001
Financial			
Federal Funds Rate	85.7	Spot	1989-2001
Stock Index, S&P 500	15.1	Spot	1989-2001
Treasury Bonds, 30 Year	12.6	Spot	1989-2001
Metals			
Copper, LME Grade A	32.3	Spot	January 1989-August 2001
Gold Bar, Handy & Harman, NY	12.0	Spot	1989-2001
Silver Bar, Handy & Harman, NY	20.2	Spot	January 1989-August 2001
Platinum, Producers	22.6	Spot	January 1989-August 2001
Agriculture			
Coffee, BH OM Arabic	37.3	Spot	January 1989-August 2001
Sugar, World Spot	99.0	Spot	January 1989-August 2001
Corn, N. Illinois River	37.7	Spot	1994-2001
Soybeans, N. Illinois River	23.8	Spot	1994-2001
Cotton, East TX & OK	76.2	Spot	January 1989-August 2001
FCOJ, Florida Citrus Mutual	20.3	Spot	Sept 1998-December 2001
Meat			
Cattle, Amarillo	13.3	Spot	January 1989-August 2001
Pork Bellies	71.8	Spot	January 1989-August 1999

Source: EIA 2002.

What states are doing

States with Retail Competition

Twenty-four states and the District of Columbia allow competitive retail sale of electricity. (EIA 2003b) Both suppliers and buyers are experimenting with processes and systems to protect themselves and their investors from volatility in electricity prices within a competitive marketplace.

Each affected state has its own legislative or regulatory mandates regarding restructuring. One consideration in those deliberations is whether and how to provide for default service. The concept for default service under retail choice is to ensure that if a customer does not choose a specific energy provider or loses that provider, the customer will automatically receive electricity from the default service provider. In some retail choice states, default service is provided under contracts issued by regulators to competitive providers who bid for the job. In other states, former incumbents are mandated to provide default service. The durations of such contracts or mandates vary between states. Contract variables include length, price of the contract, and fuel (renewable vs. coal.). Compensation and cost recovery arrangements also vary. Broadly, three processes are used to acquire energy for default service in a retail choice context:

[11] The average of the annual historical price volatility.

- Competitive bid for retail service by generators
- Cost-based rates based on utility generation costs and purchase commitments, and
- Wholesale spot market prices directly passed on to buyers.

For example, in Rhode Island, default service is competitively bid in 6 months increments, while in Maine, contracts are bid annually. Other states, such as Massachusetts, do not have a competitive bidding process for default service. Instead, the utilities can directly pass wholesale spot market prices on to consumers.

Some states, including New York, have demonstrated that multi-year contracts provide investment incentives. Consolidated Edison is offering a 10-year purchase contract in order to attract generation investment into the New York City region. (Oppenheim 2003) In this case, longer-term contracts for default service are being used as portfolio management tools that protect market participants against service instabilities.

Table 4.2. Default Term in Various States.

State	Default Term
Connecticut	4 years, ending Dec. 2003
Maine	3 years, ending Dec. 2004
Maryland	2-8 years, ending between 2002 and 2008
New Jersey	34 months 1/3 of supply ending June 2006, 10 months for 2/3 supply

Source: Besser 2003; Alexander 2002.

Montana delayed complete retail access for all consumers to July 2004, because the region does not have a competitive power supply market in place. In March 2003, Montana adopted *Rules Pertaining to Default Electricity Supply Procurement Guidelines.* These rules set forth a process and policies that must be followed by "default supply utilities (DSU)." A DSU must "plan and manage its resource portfolio in order to provide adequate, reliable and efficient annual and long-term default electricity supply services at the lowest total cost." [Rule V (38.5.8209)] A DSU may, but is not required, to offer a green or renewable energy product. The DSU is obligated to acquire its portfolio based on long-term needs and risk analysis. The term "long term" is not specified, but is defined as the longer of the term of any existing contract in the DSUs portfolio, the longest term of any contract under consideration for acquisition, or 10 years. The guidelines also make clear that DSM resources must be considered. Competitive bidding is not required, but to the extent that the DSU does not rely on competitive solicitations, it must justify its approach. The resource acquisition rules for DSM programs reflect the prior least cost planning rules that remain in effect in Montana for vertically integrated utilities. There is a prohibition on using a non-participant test (see “RIM Test” in Appendix B), targets to achieve a steady and sustainable use of demand side resources, and "cream skimming" in DSM programs is prohibited. (Alexander 2003) In addition, in Montana, default service must be provided for a lengthy transition period that does not end until July 1, 2027, thus ensuring a long planning and acquisition horizon.

States without Retail Competition

The electric industry remains vertically integrated in many states, and some have adopted portfolio management practices. Many states have Integrated Resource Planning (IRP) requirements which server to protect providers and consumers from spot market price volatility (among *many* other purposes). IRPs are used to evaluate alternative generation and end-use efficiency investments in terms of their financial, environmental, and social attributes, as well as reliability impacts. The overall impact of IRP programs has been to increase utility investment in energy efficiency and environmentally desirable generation technologies like cogeneration, wind, small hydro, biomass, and solar. (Jaccard 2002)

For example, Georgia's 1991 IRP requirements call for utilities to file a plan at least every three years that includes a 20-year projection of energy requirements and considers the economics of all options available to meet these requirements, including supply-side resources, demand-side resources, purchased power, and cogeneration. Long-term plans for the type of facility needed, the size, and the required commercial operation date are determined and approved by the GPSC. Before construction of a facility has begun or a purchased power agreement is finalized, the GPSC must first certify the need for the facility, contract or conservation program, and determine that it is the appropriate type facility based on economic analysis. Once certified, the utility is guaranteed recovery of the actual incurred costs. The IRP Act is intended to provide the GPSC a means to ensure that a reliable supply of low cost energy will be available long-term.

Table 4.3. IRP Programs for Selected States without Retail Choice

State	Initiation of IRP (year)	Frequency of Filing
Georgia	1991	Must file every 3 years
Oregon	1989	Must file every 2-3 years
British Columbia		Currently not required
Utah	1992	Must file every 2 years
Idaho		Must file every 2 years
Vermont	1991	Must file every 3 years, but waived for several years; new IRPs due for all retail electric utilities during 2003-4
Washington		In concept every 24 months, but frequency has varied.

Source: (NPPC 2003)

Other states, such as Washington and Oregon, do not include a pre-approval element to their IRP, instead relying on traditional after-the-fact prudence review. This practice is being considered in IRP rulemakings, in light of arguments from the financial community that pre-approval by the regulatory body is viewed as a valuable risk-mitigating measure.

Use of Longer-Term Contracts by Electric Utilities

Because electricity prices have been regulated for most of the last century, price risk management is relatively new for this market. However, some companies have been working toward a portfolio management approach. For example, in 2002, PacifiCorp relied on short-term and spot market electricity purchased for no more than 20.5% of total energy requirements. (PacifiCorp 2003)

In other settings, regulatory policy requires many utilities, such as natural gas companies, to purchase a mix of contract durations in order to control price volatility. Actions to stabilize gas prices have been ordered or authorized in Arkansas, Kentucky, Georgia, Colorado, Iowa, Oklahoma, Kansas, Missouri, Mississippi, and California. While most recent regulatory attention has focused on gas volatility, the same principles apply to peaks in electricity prices. (Oppenheim 2003)

Long Term Gas Supply Contracts: Failure to Hedge

Electricity companies continue to look to other energy industries for reasons to engage in longer-term contracts. One example occurred not too long ago, wherein the Nevada Public Utilities Commission found that Southwest Gas Corporation failed to use strategies to reduce price risk in 1996-1997. The Commission found that Southwest could and should have been in tune with price risk techniques. Southwest failed to research the use of fixed price contracts in its gas supply portfolio and failed to investigate advantages of financial hedging mechanisms that could have protected customers from significant price increases over the 1996-1997 winter season. As a result, the Commission disallowed $4.7 million of gas costs. (Costello 2001)

Derivative Use in Electricity Markets

Industry participants have agreed that the use of derivatives could help to limit market risk in a deregulated electricity industry, not only for the individual utility, but for the market as a whole. For instance, overall market volatility has actually declined significantly with use of derivatives in the commodity markets for cotton, wheat, onions, and pork bellies. (EIA 2002) Derivative instruments are most efficient and successful in commodity markets with large numbers of informed buyers and sellers and in those markets where there is timely, public, and accurate information on prices and quantities traded. And thus, the prospect for an active electricity derivatives market is directly linked to industry restructuring; until electricity spot markets work well, the successful use of electricity derivatives will be limited. (EIA 2002)

Hedging however can still be effective in the meantime. One means to do this is through creative derivatives that do not rely solely on the underlying spot price of electricity. For example, weather hedges have been used by some utilities to build climate adjustments built into their fuel supply contracts. (EIA 2002) In addition, power plant owners can purchase or trade SO_2 and NO_X allowances, as established by the Clean Air Act, to manage their permit price risk. Similarly, companies can buy insurance against certain improbable events. One example is the use of multiple trigger derivatives. For instance, a power plant might be paid money if it experiences a forced outage during a period when the spot price also exceeds an agreed upon spot price.

There is also evidence that hedging through use of derivatives has great potential for mitigating risk. Gas futures, for example, are now highly standardized, even though the New York Mercantile Exchange (NYMEX) first offered them only in April 1990. After a slow start, natural gas market participants now make extensive use of the futures market. Futures markets now allow marketers to offer a range of pricing options to their customers. In addition, some gas utilities have recently begun hedging as a tool to offer their customers gas at fixed prices. Gas futures are now much more liquid and, therefore, more easily traded than forward, fixed-price gas contracts. In addition, gas derivatives generally have lower transaction costs than forward contracts due to their liquidity. All of this suggests a good eventual outlook for the electricity markets, which are currently only thinly traded beyond a few years. (Costello 2001)

Hedging by Pacificorp

PacifiCorp uses a procurement and hedging strategy to ensure a low cost, safe, and reliable supply of power. This includes investment in cost-effective demand-side management programs, construction of peaking units, and purchases of weather derivatives, forward power contracts, and other portfolio optimization opportunities. The company's summer season procurement strategy uses both financial and physical hedging instruments beyond standard on-peak products. The standard on-peak product available from the over the counter market is a block purchase that requires taking the power for 16 hours a day, 6 days a week. If PacifiCorp were to purchase enough such blocks to meets its absolute one-hour peak, it would be excessively long in all the other on-peak hours. If it does not, it would be subject to excessive price swings in what the company calls "superpeak" hours. To minimize risk and save money for both the customers and PacifiCorp, the firm uses daily call options, 15-year leases with early termination rights on physical plants (a resource-based contract), and weather derivatives. (PacifiCorp 2003)

5. Forecasting Electricity Demand

5.1 The Importance of Load Forecasts

Load forecasts play an essential role in electricity portfolio management, as they provide the foundation for making decisions about the need for generation, transmission, and distribution facilities. Load forecasts also play a critical role in assessing the potential for energy efficiency resources, because they can reveal the amount and type of electric end-uses and their associated efficiency opportunities. Furthermore, electricity forecasts, and associated forecasting scenarios, provide regulators and utility planners with information necessary to anticipate how future events might affect customer demand. This information is important for analyzing risk and developing a flexible, adaptable resource plan. (NARUC 1988)

Regulators should require utilities to prepare and submit detailed, properly documented load forecasts as part of their portfolio management obligations. It is important that regulators have access to reliable, accurate and well-documented load forecasts for their oversight and review of utility resource plans. As described in more detail below, good load forecasts are necessary for the regulatory review of plans to meet both T&D services and generation services, regardless of whether a utility is vertically integrated or distribution only.

In this report, we will use "demand" in the economic sense of consumer requirements, and when we refer to electricity "load" forecasts, we are referring to forecasts of both electric energy demand (in MWh) and electric peak load (in MW). Where not explicitly stated otherwise, the following discussion will presume that forecasts of energy and peak load will be prepared for the relevant time periods, whether years, seasons, days of the week, or times of the day. It is important for utilities to forecast both types of demand, because the size of energy and peak demands will have different implications for the types of supply-side and demand-side resources that could be used to meet that demand.

5.2 Standard Forecasting Techniques

Econometric forecasting models have been used by electric utilities for many years to forecast electricity demand. These models correlate electricity demand with relevant economic and demographic indicators, such as electricity prices, population growth, gross state product, and heating and cooling degree days.[12] While econometric forecasting techniques and models are well-established in the electric industry (as well as other industries), they suffer from a lack of detail and an inability to address changes in

[12] Time series projections (statistical projection methods that correlate the forecasted loads only or primarily with time, past values of the load, or both) may sometimes be adequate for short-term projections, but do not capture structural or feedback effects and should usually not be relied on for long-term projections.

end-use technologies or changes in the relationships between electricity demand and the factors with which it is assumed to be correlated. (NARUC 1988) For those utilities in regions with retail choice it is even more important to be able to some of these changes.

End-use forecasting models have been used by electric utilities since the 1980's and 90's, to address some of the limitations of econometric forecasting models. End-use models use a "bottom-up" approach, which analyzes each contribution to electricity demand, such as lighting measures, appliances, space-heating equipment, refrigeration equipment, motors, etc. The model forecasts the number and type of all the end-uses in a utility's service territory, and multiplies those by estimates of electricity consumed per end-use, to derive the total load forecast.

The advantage of end-use forecasting is that it allows the user to analyze changes in electric end-use technologies and customer usage patterns, which is necessary for a comprehensive assessment of energy efficiency and load control resources and for integrating the forecasting effort with the demand-side management planning. The disadvantage of this approach is that simpler versions do not capture the effect of economic and demographic changes that are likely to affect electricity demand. (NARUC 1988)

This limitation can be addressed by using forecasting models that combine both econometric and end-use techniques. These combined models provide utilities with the best capability for portfolio management, and provide regulators with the greatest opportunity to review and oversee portfolio management practices.

There are many uncertainties involved in forecasting future electricity demands. Electricity prices, macro-economic effects, evolution of changing technologies and the rates at which they penetrate the relevant markets, weather, the costs of competing fuels such as natural gas, and other factors can have a substantial effect on customer electricity usage.

Utilities should address these uncertainties in at least two ways. First, they should explicitly identify the assumptions that they have made regarding the key factors that might affect electricity demand in the future, so that regulators can assess for themselves the uncertainties embodied in these assumptions. Second, utilities should conduct sensitivity analyses, where alternative assumptions are made regarding these key factors, to indicate how the load forecast might change under a different future. These sensitivity analyses can also be grouped into future scenarios (e.g., low load growth, expected load growth, and high load growth), to indicate the likely range of electricity demand under very different future conditions. Additional methods, such as Monte Carlo simulations varying multiple factors simultaneously, may be warranted.

5.3 Considerations in a Restructured Electric Industry

Load forecasting techniques are by now well-established in the electric utility industry. However, electricity industry restructuring and portfolio management in that setting raise several new issues for utilities and regulators to consider.

First, it is important that regulators explicitly require utilities to provide detailed descriptions and documentation of their load forecasts as part of their portfolio management obligations. Load forecasts play such an important role in demand-side management, distributed resource planning, and portfolio management in general that regulators must be able to review them periodically in order to ensure that the objectives of portfolio management will be achieved.

Second, distribution-only utilities in states with retail electricity competition should be required to prepare and present separate load forecasts for T&D services and for default generation services. As customers choose to purchase generation services from competitive suppliers, the demand for T&D services will differ from the demand for default generation services. A thorough, reliable forecast of T&D demands will be necessary for demand-side management planning and distributed resource planning, as well as other utility planning needs. And a thorough, reliable forecast of generation demands will be necessary for proper management of the default service generation asset portfolio.

Third, the forecast of demand for default service must include a comprehensive assessment of the competitive electricity market over the short-, medium- and long-term future. The potential for customer switching to competitive generators represents a new and challenging load forecasting uncertainty that must be assessed thoroughly. Utilities and portfolio managers should not simply assume that all default service customers will switch to the competitive market within the short-term future, thereby unburdening them of the obligation to manage the default service portfolio or, conversely, that those customers will remain on default service indefinitely.

The forecast of default service demand must include a detailed estimate of future default service customer retention rates. This estimate should be based on an up-to-date analysis of the competitive electricity market in the state and region of interest, including, by customer class, assessments of:

a) the extent to which customers have switched to (or back from) alternative generators in the past;

b) likely changes in prices in the wholesale electricity markets;

c) the extent to which the retail electricity market will become more competitive in the future;

d) how competitive generation services will compare with the default service offers;

e) the types of customers likely to switch to competitive generation service, as well as the load shapes associated with those customer types, including any differences between those types of customers (or their load shapes) and those that are expected to remain on default service; and

f) the customers that might return to default services after switching to competitive generation service.

Default customer retention will clearly be affected by default service prices, so the utility should integrate this analysis with the development of the preferred generation portfolio.

Fourth, in competitive markets, the forecast of demand for default service should include a broader range of sensitivities than typically used by a vertically-integrated utility or for the T&D demand for a distribution-only utility. Default service demand in a competitive market is inherently more uncertain than the demand for T&D or generation services where customers do not have retail choice. This uncertainty does not eliminate the need of each utility to make a forecast, rather, calls for even more creativity and analysis in recognizing, assessing and accounting for that uncertainty.[13]

Fifth, forecasts should account for the relationships between regulatory policy and utility forecasts. If regulators impose no restrictions on customers moving from competitive to default service, large sophisticated customers will move back and forth with high frequency – whenever one or the other offers a temporary price advantage. This was experienced in extreme terms in the early years of competitive gas transportation service, with industrial customers switching on a daily basis. If, on the other hand, significant exit fees, re-entry fees, vintaging, or other sanctions are imposed on migratory customers, the utility's default service load will be more stable.

One important step towards providing this increased attention to planning in the face of uncertainty is to include sensitivities in the default services demand forecast that reflect the full range of likely customer retention rates. Another important step is to develop a portfolio of demand-side and supply-side resources that is dynamic and flexible enough to respond in relatively short time periods to deviations from the expected demand for default generation services. Methodologies for achieving this latter step are described in the following chapters.

Finally, as the roles for providing default and competitive generation services become spread across more than one entity (competitive generators, distribution utility, other default providers, etc.), it will be important for regulators to clarify who has responsibility for making comprehensive load forecasts. For regulatory, planning and reliability purposes, it will be necessary to have a consistent set of forecasts covering all electricity services, regardless of who eventually provides the service. The distribution utility is the obvious candidate for making such forecasts, but some states may prefer other options. Either way, whoever prepares the forecast will need to be compensated for its forecasting efforts, and there should be procedures in place to protect competitively sensitive information.

---

[13] This concept is similar to that of forecasting fossil fuels prices. It is widely understood that the forecasts of fossil fuels (especially natural gas) are inherently uncertain, and are rarely accurate. It is also widely understood that planners need to prepare the best forecast of fossil fuel prices possible, and to account for uncertainty through other aspects of the planning process.

6. Evaluating Options for Managing Electricity Demand

6.1 The Many Benefits of Energy Efficiency

Throughout the United States there is a vast potential to improve the efficiency with which electricity is used. All types of electricity customers have numerous opportunities to replace aging electric equipment with newer, more efficient models, or to buy a high-efficiency product when purchasing a new piece of electric equipment.[14] There is a long and ever-growing list of new technologies to reduce electricity consumption, including compact florescent lighting; efficient refrigerators; efficient heating, ventilation and air conditioning equipment; efficient motors; water heater improvements and insulation; weather-stripping of houses and businesses; and more. (Interlaboratory Working Group 2000) There are also many design and behavioral modifications that allow citizens and businesses to manage their energy use more efficiently.

Since the 1980s many electric and gas utilities have used energy efficiency programs to manage customer demand.[15] In integrated resource planning (IRP), energy efficiency programs have been viewed and used as "resources" to meet customer demand, in much the same way that power plants represent resources available to the utility.

Many efficiency measures cost significantly less than generating, transmitting and distributing electricity. Thus, energy efficiency programs offer a huge potential for lowering system-wide electricity costs and reducing customers' electricity bills. A fundamental principle of IRP is that utilities should identify, assess and implement all the demand-side resources that cost less than supply-side resources.

In addition to lowering electricity costs and customers' bills, energy efficiency offers a variety of benefits to utilities, their customers, and society in general.

- Energy efficiency can help reduce the risks associated with fossil fuels and their inherently unstable price and supply characteristics and avoid the costs of unanticipated increases in future fuel prices.
- Energy efficiency can reduce the risks associated with environmental impacts. By reducing a utility's environmental impacts, energy efficiency programs can help utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO2 regulation.

---

[14] Energy efficiency as used in this report is defined as technologies, measures, activities and programs designed to reduce the amount of energy needed to provide a given electricity service (e.g., lighting, heating, refrigeration, motor power). In other words, the level of electricity service to customers is maintained or improved, while the amount of energy required is reduced.

[15] Most of these programs have focused on measures to influence customer usage behavior and customer adoption of energy efficiency measures. There are also many important opportunities to influence the market of energy efficiency technologies through building codes and equipment efficiency standards.

- Energy efficiency can improve the overall reliability of the electricity system. First, efficiency programs can have a substantial impact on peak demand, during those times when reliability is most at risk. (Nadel 2000) Second, by slowing the rate of growth of electricity peak and energy demands, energy efficiency can provide utilities and generation companies more time and flexibility to respond to changing market conditions, while moderating the "boom-and-bust" effect of competitive market forces on generation supply. (Cowart 2001)
- Since efficiency programs have a substantial impact on peak demand, they help reduce the stress on local transmission and distribution systems, potentially deferring expensive T&D upgrades or mitigating local transmission congestion problems. (This issue is addressed in more detail in the Chapter 7.)
- Energy efficiency can result in significant benefits to the environment. Every kWh saved through efficiency results in less electricity generation, and thus less pollution.[16] Energy efficiency can delay or avoid the need for new power plants or transmission lines, thereby reducing all of the environmental impacts associated with power plant or transmission line siting.
- Energy efficiency can also promote local economic development and job creation by increasing the disposable income of citizens and making businesses and industries more competitive compared to importation of power plant equipment, fuel, or purchased power from outside the utility service territory.
- Energy efficiency can help a utility, state and region increase its energy independence, by reducing the amount of fuels (coal, gas, oil, nuclear) and electricity that are imported from other regions or even from other countries.

6.2 The Role of Ratepayer-Funded Energy Efficiency in the Past

Integrated Resource Planning and Electricity Industry Restructuring

Electric utilities began implementing energy efficiency programs since the early 1980s.[17] In the late 1980s and early 1990s there was a significant increase in utility investments in energy efficiency programs, partly as a result of increased support from regulators through IRP and related policies. In many states, energy efficiency programs were seen by regulators and utilities alike as an essential component of a vertically-integrated utility's portfolio of resources.

With the introduction (or the prospect of) of electricity restructuring during the 1990s, the energy efficiency programs offered by utilities began to contract dramatically. In 1993

---

[16] Unlike other pollution control measures – such as scrubbers or selective catalytic reduction– energy efficiency measures can reduce air emissions with a *net reduction* in costs. Thus, energy efficiency programs should be considered as one of the top priorities when investigating options for reducing air emissions from power plants.

[17] In some cases, utilities offered weatherization and other early programs in the late 1970s in response to oil price shocks.

electric utility investments in energy efficiency peaked at roughly $1.6 billion nation-wide; by 1997 they had dropped to roughly $900 million, a decline of about 44 percent and a sharp turnaround in the previous growth. (York and Kushler 2002)

This decline in energy efficiency investments was driven by many factors. Regulators relaxed or ignored IRP and demand-side management (DSM) policies in the light of retail competition policies which advocated for more reliance upon market forces and less regulatory oversight. Utilities were concerned that successful energy efficiency programs would limit their ability to recover stranded costs, or that they would be unable to recover their energy efficiency investments from a shrinking customer base.

Some regulatory policies introduced at the time of restructuring, such as performance-based ratemaking, can, unless properly designed, make it more difficult for utilities to recover their energy efficiency costs. (Kushler 1999) In addition, the separation of generation providers from T&D utilities created an apparent split in the incentives for implementing energy efficiency: should efficiency be provided by a T&D utility, and if so, should the avoided cost of generation be used to justify the efficiency investments?

Administratively-Determined Energy Efficiency

In response to these concerns, some states that introduced electricity competition have also introduced a new policy – the system benefits charge (SBC) – to ensure that efficiency would continue to provide benefits to electricity customers. Often established through legislation, the SBC is a fixed charge collected from all distribution customers, regardless of generation service provider, to fund DSM programs (and in some cases other activities that offer public benefits). In this way, the electric utility is guaranteed to recover its energy efficiency costs, regardless of competing regulatory polices and regardless of the extent to which customers switch to alternative electricity suppliers.

SBC policies explicitly acknowledge that there is still an important role for energy efficiency activities in a restructured electricity market and that the market barriers that discourage optimal levels of investment in efficiency still exist. They also acknowledge that distribution utilities are in the best position to collect funds for energy efficiency programs, and in many cases to implement or manage implementation of those programs. They are also based on the notion that, while the benefits of energy efficiency such as price risk reduction, avoided generation costs, and avoided T&D costs might accrue to different market actors, there is a role for regulation to play in making sure that those benefits are somehow obtained through the remaining regulated utility.

SBC policies have been primarily responsible for a turnaround in the decline in energy efficiency investments in recent years. Since 1998 US electric utility expenditures on energy efficiency have increased slightly, to about $1.1 billion in 2000. (York 2002)

For the purposes of this report, we refer to energy efficiency activity supported by a system benefits charge as "administratively-determined." This is because the amount of energy efficiency funding is often set through legislative negotiations, and is not based on an assessment of the full potential of energy efficiency to meet customer demand. This type of energy efficiency activity is different from that based on IRP practices, where the efficiency is considered a resource that should be compared directly with supply-side resources. We refer to this latter type of efficiency activity as "resource-driven."

While the actual programs implemented through administratively-determined energy efficiency might be similar or identical to those implemented through resource-driven energy efficiency, the amount of funding and the overall mandate may be very different. The amount of efficiency funding available through system benefits charges tends to be well below the amount of funding that would be necessary to acquire the full cost-effective energy efficiency resource. In many states, the amount of energy efficiency funding from the SBC is significantly lower than the amount that had previously been available when efficiency programs were based on an IRP process.

Efficiency Funding Levels under SBC and IRP

As one example, in Massachusetts electric utilities spent roughly 3.8% of total electric revenues on energy efficiency programs in 1994, when the funding was based on an IRP process. Since 1997 the efficiency program funding has been based on a legislatively-determined SBC, and the energy efficiency funding currently represents roughly 2.4% of total electric revenues. (MA DTE 2003) The Massachusetts SBC is currently set at $2.5/MWh, and is the third-highest SBC in the country. (ACEEE 2003)

Non-Utility Energy Efficiency Program Administrators

Recently, several states have begun looking for alternative entities to administer energy efficiency programs. This change has partly been driven by restructuring activities and some of the concerns listed above regarding the role of distribution-only utilities in providing energy efficiency services.

Some states (ME, IL, OH, WI and NY) shifted the responsibility for energy efficiency administration to state government. Oregon has established an independent, non-profit agency, the Energy Trust of Oregon, Inc., to administer the energy efficiency programs there. Vermont established a new function, the Vermont Energy Efficiency Utility, to act as a regulated energy efficiency utility independent of the electric utilities in the state and bid out that function competitively. (Harrington 2003)

Other states (CT and MA) explicitly decided to leave the energy efficiency responsibilities with the distribution-only utilities. Massachusetts also allowed towns and cities to establish municipal aggregators to provide generation service to all customers in their boundaries, and to replace the local distribution utility as the provider of energy efficiency programs. To date only one municipal aggregator, the Cape Light Compact covering all of Cape Cod and Martha's Vineyard, has taken advantage of this option.

6.3 The Role of Energy Efficiency in Portfolio Management

The primary rationale for implementing energy efficiency programs – to reduce electricity costs and lower customer bills – is just as relevant in today's electricity industry as it has been in the past. It is just as relevant in a restructured electricity industry with retail competition as it is in state or region with fully-regulated, vertically-integrated utilities.

Furthermore, some of the other benefits of energy efficiency are even more valuable in today's electricity industry than in the past. Recent spikes in the price of natural gas and the prices of some wholesale electric markets illustrate the risk-reduction benefits of energy efficiency. Maintaining electric reliability during peak hours can be more challenging and expensive in a restructured wholesale electricity market. Concerns over the environmental impacts of the electricity industry have increased over time, and the likelihood of future carbon regulations increases with each passing year. Energy efficiency is also more valuable in a competitive wholesale market, as it can make the demand side of the market more responsive to the effects of the supply side (e.g., price spikes, volatility, and market power abuse).

Portfolio management (PM) provides a methodology and a regulatory forum to obtain the many benefits of energy efficiency, regardless of the industry structure. PM explicitly recognizes that both vertically-integrated and distribution-only utilities have an essential role to play in managing the electricity resources used to serve electric customers. The management of these resources will be most efficient, and provide the greatest benefits to customers and society, if it includes *all* cost-effective resources on both the demand-side and the supply-side.

Even in a restructured electric industry, distribution-only utilities are well-positioned to support the implementation of energy efficiency programs, for several reasons:

- First, the distribution utility retains a business relationship with each customer connected to the grid. No other energy supplier has an equally universal relationship with retail consumers.
- Second, energy efficiency can contribute to meeting the utility's T&D service obligations at least cost and with reduced risk.
- Third, to the extent that a distribution-only utility provides default service, it can use energy efficiency as means of reducing the cost and risk of that service.
- Fourth, even if a distribution-only utility provides little or no default service, it is still well-positioned to support energy efficiency activities by (a) assessing the full potential for cost-effective energy efficiency, (b) raising the funds needed to support the efficiency through an SBC, and (c) implementing programs if no other agency is designated to do so.
- Finally, and very importantly, distribution utilities have an obligation to implement cost-effective energy efficiency resources in order to comply with their mandate to provide low-cost, reliable, and safe power to their customers.

6.4 Methodologies for Assessing Energy Efficiency Potential

Avoided Costs of Electricity Generation, Distribution, and Transmission

The methodologies for assessing the potential for energy efficiency under portfolio management are essentially the same as those that have been used in the past in the context of IRP. To summarize, portfolio managers should compare the costs and benefits (including risk reduction) of energy efficiency resources with those of supply-side resources, and select the combination of the two that results in the lowest costs and the greatest benefits to the utility and its customers.

Ideally, portfolio managers should iterate between the analysis of energy efficiency potential and the analysis of supply-side potential, to create a truly integrated plan, because the decisions made regarding the amount and type of energy efficiency resources will affect the costs and impacts of the supply-side resources, and vice-versa. In practice, however, it is common to shorten the analysis by estimating the "avoided costs" of generating, transmitting, and distributing electricity, and comparing these to the costs of implementing the energy efficiency. Those energy efficiency measures and programs that cost less than the supply-side avoided costs are considered to be "cost-effective," and should be implemented as part of the utility's resource plan.

It is important to note that even where retail competition is allowed, the avoided costs used to evaluate energy efficiency programs should include the costs of generation as well as transmission and distribution. This is necessary to enable portfolio managers to identify and implement energy efficiency resources that help lower the costs of providing default service. It also remains important in those instances when distribution-only utilities are no longer providing default service. In such instances, the distribution-only utility would be acting as an agent for identifying the full potential for energy efficiency, and for collecting the funding for that energy efficiency, in order to ensure that the benefits of energy efficiency will accrue to the entire electric system and its customers. As described above, distribution utilities are in the best position to play this role in a fully restructured electricity industry.

Furthermore, for many peak-oriented end-uses, such as air conditioning, the value of avoided transmission and distribution costs may equal or exceed the value of the energy savings. In addition, efficiency savings reduce losses, which contribute to both energy savings and to peak demand savings. A lower load means a lower reserve capacity requirement, and this value must also be taken into account. Finally, avoided environmental costs should be computed, and should clearly be incorporated in the societal cost test discussed below.

Different Perspectives on Energy Efficiency Costs and Benefits

There are several additional considerations in deciding which energy efficiency measures and programs should be considered cost-effective. The costs and benefits of energy efficiency differ from those of supply-side resources, and have different implications for different parties. As a result, five tests have been developed to consider efficiency costs and benefits from different perspectives. These tests are described in Appendix B.

In theory, all of these tests should be considered in the evaluation of energy efficiency resources. (CA PUC 2001) Some programs will require trading-off one perspective versus another (e.g., some programs might not pass the Rate Impact Measure (RIM) test but offer substantial benefits according to the other tests). The portfolio manager has the responsibility to carefully consider what tradeoffs should be made in order to determine the optimal selection of efficiency resources. It is important to keep in mind that none of these tests directly quantify the value energy efficiency measures have with respect to reducing portfolio risk or mitigating market power, prices and price volatility.

In practice, regulators tend to adopt one of these tests as the primary guideline for screening energy efficiency programs. The remaining tests can then be used, if needed, to provide additional information about programs that might be marginally cost-effective.

In recent years, most regulators have adopted the Total Resource Cost (TRC) test as the primary methodology for defining energy efficiency cost-effectiveness. The TRC test reflects the total direct costs and benefits to society, and therefore provides a more comprehensive picture than the other tests.[18] In other words, applying the TRC test will result in the minimum direct total cost to society, and is thus considered "economically efficient," at least if external costs are neglected. (Krause 1988) The Societal Cost test is rarely used because of the technical and political difficulties of estimating the monetary values of environmental externalities. The Rate Impact Measure test is rarely, if ever, used to screen energy efficiency programs for reasons discussed in the following section.

Accounting For Potential Rate Impacts

Energy efficiency programs can sometimes lead to small increases in electric rates. These increases are not due to the costs of the efficiency programs themselves (e.g., the SBC), because over time these costs are offset by the efficiency savings. Rather, the rate increase is due to the fact that a utility's energy sales will decline as a result of the efficiency savings, and electric rates may not sufficient to recover the existing fixed costs on the system. Paradoxically, electric rates may need to be increased even though the total cost of providing electricity has been reduced, and electric bills, on average, have declined. The RIM test identifies the extent any potential increase in electric rates.[19]

Portfolio managers should consider both rate and bill impacts of DSM programs. Rate impacts have always been a concern for utilities, regulators, and electricity customers. Rate impacts may be even more important in those states with retail competition as they may encourage customers to switch from the default service provider to alternative generation companies. However, the RIM test should not be used as the primary tool for determining the cost-effectiveness of energy efficiency programs. The reasons are discussed in Appendix B, but chief among them is that using the RIM test will not result in the lowest cost to society.

Even if the RIM test is not used to screen energy efficiency programs, there are two remaining rate effect issues that may be of concern to utilities and policy-makers. The first issue is that rate impacts of sufficient size can be considered a problem – despite the fact that they are a consequence of creating a lower-cost electricity system. This issue should be addressed by evaluating the package of energy efficiency programs as a whole,

---

18 With the exception of the Societal Cost test.

19 It is important to note that any such "lost revenues" do not impact rates until the utility's rates are adjusted to account for the difference in sales, typically during the utility's next rate case. Between rate adjustments, lost revenues reduce the utility's profits, but do not increase customers' rates. If revenues have been decoupled from sales, the impact may occur sooner, depending on the mechanism.

including those programs that might increase rates and those that might decrease rates, and quantifying the potential rate impacts over time. These rate impacts should then be compared to the expected reductions in total electricity costs, so that the portfolio manager and regulators can evaluate the trade-off that might have to be made between lower costs and higher rates. Experience with energy efficiency programs in the past has demonstrated that significant reductions in costs can be achieved with very small increases in electricity rates.

Also, it is important to consider long-term rate impacts and long-term reductions in electricity costs. Often the rate impacts occur only in the short-term, while cost savings can last over many more years.

The second issue is the equity effects between efficiency program participants and non-participants. While this should not be a driving factor in selecting electricity resources, it is nonetheless good public policy to mitigate equity effects between customers. There several ways that the equity impacts of energy efficiency programs can be mitigated, or eliminated, through efficiency program design and implementation, including:

- Efficiency programs should be designed to provide opportunities to all customer classes and subclasses, and to address as many electric end-uses and technologies as possible within cost-effectiveness guidelines
- Efficiency programs should be designed to minimize the costs incurred by the electric utility (or program administrator). To the extent that customer contributions can be secured without adversely affecting the level of program participation, rate impacts can be lessened.
- Efficiency programs should be designed to maximize the long-term avoided costs savings for the electricity system.
- Efficiency programs that result in lower rates should be combined with those that might increase rates, to lower the overall rate impact.
- Budgets for efficiency programs targeted to a specific customer class (i.e., low-income, residential, commercial, industrial) may be based on the amount of revenues that each class contributes to the efficiency funds if equity impacts are determined to be severe.

6.5 The Relationship between Portfolio Management and SBCs

System Benefit Charges Do Not Address the Full Potential for Efficiency

The introduction of a system benefits charge to finance energy efficiency does not eliminate the need for portfolio managers to assess the full potential for energy efficiency to reduce electricity costs. Because SBC's tend to be set through legislation (i.e., administratively-determined), they are not typically based on a comprehensive assessment of the potential for cost-effective energy efficiency resources to displace supply-side resources. As a result, all of the system benefits charges in place today fall far short of capturing the full potential for energy efficiency to reduce electricity costs.

In fact, system benefits charges were never intended by their proponents to address all cost-effective energy efficiency opportunities, or to be the only means by which utilities or others could implement energy efficiency programs. They were intended to provide a minimum amount of support at a time when electric utilities were drastically cutting back on efficiency efforts due to concerns about restructuring. (NRDC 2003)

So, there is clearly room for additional energy efficiency activities beyond those supported by a system benefits charge. What is relevant to this report is the risk reduction and PM benefits that such programs can provide. Those benefits were reviewed above and will be discussed further in Chapters 8 and 9. Here, we will consider trends in how those programs might be institutionalized. As described above, vertically-integrated utilities and distribution-only utilities are both well-positioned to identify this potential, and are obligated to identify and promote this potential as part of their mandate to provide low-cost, reliable, and safe power to their customers.

Energy Efficiency and Portfolio Management in California's Recovery

Legislators, regulators, and utilities in California have recently taken steps to promote energy efficiency resources as part of the portfolio management process, and to implement energy efficiency programs that go well beyond those funded by the state's SBC:

- In September 2002, Gov. Davis signed legislation requiring utilities to periodically develop "resource procurement plans" for Commission review. The plans must demonstrate that the utilities will "create or maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity related and *demand reduction* products (emphasis added). (CA Legislature 2002, page 87)
- In October 2002, the California Public Utilities Commission issued an order requiring distribution utilities to resume procurement of resources to meet customer electricity demands. The order requires distribution utilities to "consider investment in all cost-effective energy efficiency, regardless of the limitations of funding through the public goods charge mechanism." (CA PUC 2002, page 27) The public goods charge is California's SBC, and is currently set at $1.3/MWh.
- In April 2003, the distribution utilities filed 20-year resource procurement plans that contain energy efficiency programs at roughly twice the size of those that can be supported through the state's SBC. (NRDC 2003)
- In May 2003, an Energy Action Plan was adopted by California's key energy agencies: the Public Utilities Commission, the California Energy Commission, and the Consumer Power and Conservation Financing Authority. The Action Plan cites energy efficiency as the top priority and notes that "the agencies want to optimize all strategies for increasing conservation and energy efficiency…" (CA Energy Action Plan 2003, p. 4)

Funding for Additional Energy Efficiency Activities

When a utility identifies cost-effective energy efficiency opportunities beyond those that can be funded through a SBC, it will be important to provide reliable and stable funding for those additional efficiency activities. Utilities will need to be assured timely recovery for any additional efficiency costs, and that change in the electricity market (e.g., customers switching to alternative generators or new restructuring regulations) will not create a financial barrier to their energy efficiency activities.[20]

Stable, reliable, and fair cost recovery policies have always been important in promoting utility energy efficiency activities, and are especially important with the uncertainties created by restructuring. Regulators should explicitly develop energy efficiency cost recovery policies to support this important component of portfolio management.[21]

One option is for regulators to allow for energy efficiency cost recovery within the utility's rates, in addition to the cost recovered through the SBC. The SBC would be considered a constant "floor" for the amount of efficiency, and the additional costs could vary over time depending upon the outcome of the portfolio management process.

Another option is to use the portfolio management process to establish the size of the system benefits charge. When a utility completes a new resource plan and identifies the potential for cost-effective energy efficiency activities, the SBC could be modified by the regulator to provide the utility sufficient funding to cover the costs of those activities. In other words, SBC's could be resource-driven and not administratively determined.[22]

Regardless of the mechanism used to recover the additional energy efficiency costs, it is essential that they be recovered through rates applied to all distribution customers. This ensures that utilities will recover their costs regardless of the extent to which customers switch to alternative generation suppliers.

Coordination of Portfolio Management with Independent Energy Efficiency Administrators

In those states where energy efficiency programs are administered by entities other than the regulated utilities or the portfolio managers, it is important that the portfolio management process be coordinated with those independent efficiency program administrators, in several ways:

- Efficiency program administrators should play a central role in contributing to the efficiency analysis of the portfolio manager. The program administrator should provide information and guidance "from the field" on the technical and economic potential for energy efficiency.

---

[20] As with all of their resource procurement activities, utilities should always be required to design and implement energy efficiency programs efficiently and prudently in order to recover their expenses.

[21] Many efficiency programs provide for cost savings on the utility's side of the meter. Examples include more efficient transformers, new substation equipment, and higher voltage distribution systems. These also cost money, but unlike efficiency measures installed on the customer's side of the meter, they do not reduce utility revenues because metered energy consumption is not affected. The cost of these types of measures should be funded by the distribution utilities without reliance on the funds generated by an SBC.

[22] Many SBC's are set by legislation, and it may be politically difficult to modify that legislation on a periodic basis. However, if legislation established the general requirements for an SBC, but enabled the regulatory commission to set the size of the SBC periodically through the portfolio management process. Another option is for the regulatory commission to establish an additional charge to be applied to all distribution customers to recover any additional efficiency costs above those covered by the SBC.

- The results of the portfolio manager's efficiency analysis should be shared with the efficiency program administrator for use in modifying programs and planning new programs to comply with the findings of the portfolio management process.
- If the SBC funding for the efficiency program administrator cannot cover all the efficiency activities identified by the portfolio manager, then the SBC funding should be modified to equal those costs, as described in the preceding section.
- The savings that efficiency provides to T&D must be added to the generation savings in evaluating potential, in order to be able to target programs where they provide the maximum benefit. The independent efficiency administrator should have full information from the distribution utilities and regional transmission system owner/operator(s) of the locational benefits of efficiency.

In sum, while the portfolio manager would have the primary responsibility for assessing the potential for energy efficiency programs, and the administrator would have the primary responsibility for implementing those programs, the two agencies should work together so that both goals are pursued in parallel.

A recent study compared the advantages and disadvantages of alternative entities for administering energy efficiency programs. (Harrington 2003) The authors concluded that the success of energy efficiency programs depends less on upon the administrator, and more upon the "clear and consistent commitment" of regulators and policy makers. They identify the following factors that are important when considering the issue of who should administer energy efficiency programs: "responsiveness to PUC direction, regulatory performance incentives that are properly constructed and implemented, staff competency, sustainability of the institution and its budget sources, and link to system planning decisions." (Harrington 2003)

These conclusions support the need for portfolio management to reflect energy efficiency activities – regardless of who administers the programs. Portfolio management should provide clear direction from regulators, policy and cost recovery support from regulators, consistency and sustainability for the administration and funding of efficiency, and a clear link to electricity system planning process and decisions

7. Evaluating Generation Options

7.1 Preliminaries

This chapter examines how generation assets fit into developing a portfolio for default service.[23] In the broadest sense, little has changed during the turmoil of the past 10 years: providers must choose between buying power or building generators and must determine the appropriate amount and types of generation assets for its needs. In another sense, everything has changed, and change shows no sign of abating. New or improved generation technologies dominate markets – markets that did not exist ten years ago. Bilateral power contracts continue to be important, but against a backdrop of shifting standards for rate-making and transmission access. Load serving entities are often required to obtain new and different power products and a wide range of ancillary services. New power products are traded in new markets, including mercantile exchanges and derivatives markets. Transactions with traders and brokers, rather than traditional utilities or independent power producers, are commonplace. In sum, the same old job still needs doing, but in a different technical, financial and regulatory environment, even for utilities operating under traditional regulation.

Portfolio development in retail choice states must take into account how the jurisdiction dealt with pre-existing ownership of generation assets. In some cases, divestiture was total, and the default service provider starts with a clean slate. In others, this provider owns plants or forward contracts covering some or all (or more than all) of the default service requirement. If such legacy assets are owned by corporate affiliates, the availability and pricing of such power can be especially problematic. Regulators should see that policies are in place to ensure default service providers deal effectively and in a least-cost manner with legacy generation assets, imposing appropriate codes of conduct and rules for affiliate transactions where needed.

7.2 Physical Generation Types

Table 7.1 lists the key planning and risk management attributes of generation technologies. Many other variables, such as remaining useful life, licensing risks, vulnerability of fuel delivery and electric transmission routes, maintainability, availability and physical reliability are also important, but should be evaluated for each plant.

Each technology has its own profile of costs and risks. Plant types with high fixed costs or long lead times can become a burden if demand fails to materialize and may not be suitable for peaking requirements. Types with high variable costs can be vulnerable to fuel price fluctuations, but often fit well in moderate quantities as peaking resources.

---

[23] As mentioned above, we use the term "default service" to encompass both the provider of last resort in a retail choice environment and the monopoly utility in a traditional fully regulated setting, and use "generation assets" to mean the entire range of physical and financial options for acquiring power.

Development of a physical generating asset mix traditionally focused on two issues: adequacy (i.e., reliability) and total cost. Within the constraint of needing to meet peak loads and total energy requirements at the required level of reliability, the mix should be optimized for cost using sound dispatch modeling and taking transmission costs and constraints into account.

For any generation asset, modularity and other types of flexibility can significantly reduce risk and, on average, result in a less costly mix. Wind farms, fuel cells and photovoltaic generators, and certain types of fossil-fueled turbine plants can be installed in modular increments, allowing the pace of development to be accelerated, slowed or halted, as circumstances dictate. This creates significant real savings through the option value such flexibility gives the portfolio manager. (Trigeorgis 1993)

A portfolio that includes smaller and more dispersed units can provide certain reliability benefits. Each generating technology has different scale properties that affect such decisions. In the past, nuclear and some coal unit designs have pushed past the 1000 MW mark, but advanced designs may target sizes one-fifth to one-half that. Combustion turbine units enjoy very significant economies and efficiencies of scale, with units in the hundreds of MW dominating utility construction, while microturbines are typically available in the tens of kW, as are fuel cells. Hydro unit costs and efficiencies are completely site specific. Optimally efficient wind turbines (and wind farms) for utility scale installations are getting larger. Solar PV efficiency is not strongly size dependent.

In summary, generation planning typically begins with finding a least-cost portfolio of just generation assets adequate to meet the forecasted demand at the required reliability level. This will usually be a mix that includes some long-term forward contracts and some resource based assets, either owned plant or contracts for specific physical resources. (This "buy vs. build" issue is discussed below and in Appendix A.)

Given ongoing restructuring trends and uncertainties in the default service market and wholesale power markets, many default service providers are reluctant to consider ownership of power plants or contracts for specific plants; some are even forbidden to do so by law. But all the same advantages and disadvantages apply in the realm of bilateral, resource-based contracts for power. Even if only market-based contracts are considered and resource-based contracts rejected, the relevant markets depend on these same physical generation technologies and market pricing and availability are subject, ultimately, to the same pressures. The challenge for regulators (or legislators) is to fashion institutional structures that drive resource planning that properly takes into account the full range of options under suitable decision rules.

Table 7.1. Key Variable for Generating Plants Technologies

Type of Plant	Up-Front Capital Costs	Variable Costs	Emissions	Construction Lead Time
Hydro	High to Very High	Very Low	Nil aside from some impacts of new flooding, but significant non-air environmental impacts	Long, except for possible re-powering of previously operated sites
Coal-fired	Moderate to High	Low if rail transportation is good; generally stable	Very High with special concerns for some fuel types; Ash disposal and cooling water issues may be important	Moderate to Long
Gas-fired	Moderate	Moderate but Volatile	Nil $SO2$, Low NOx with proper control, $CO2$ lowest of fossil fuels with combined cycle units	Low if pipeline capacity is available
Oil-fired	Moderate	Moderate but Volatile	High except Moderate for distillate fuel	Moderate
Cogeneration	Site and fuel specific	Fuel specific but net fuel cost can be low if displacing other fuel used for heating or cooling	Fuel and technology specific, but can be Low or Very Low if on-site fuel use is displaced	Site and fuel specific
Geothermal	Moderate to High, and site specific	Low to Moderate depending technology and site	Nil air emissions but some ground water disposal challenges can be serious	Site specific, often long
Wind	High	Very Low	None but can have significant aesthetic and land use impacts	Site specific but can be Long; depends on state of prior wind resource surveys
Fuel Cells	High to Very High	Fuel dependent	Nil for hydrogen, Very Low for natural gas, Low for other fuels	Short for currently available size units
Solar	Very High	Nil	Nil	Very Short
Pumped Storage	High, and site specific	Depends on cost spread of on and off peak power in applicable market	Same as emissions from off peak power used (plus losses of about 1/3)	Very Long
Nuclear	Very High	Low to Moderate	Air emissions Nil, cooling water requirements can be large, Radiological emissions and waste production High	Very Long but potential approval of standardized new designs may reduce lead time

7.3 Buy Versus Build Decisions

Electricity providers have available to them a unique strategic option: to build and operate generation facilities instead of or alongside outsourcing power supply. Some default service providers may be uniquely positioned to take advantage of generating plant construction and ownership. Under traditional rate regulation, ownership of generation was often the norm; primary reliance on purchases was mainly a strategy used by municipal and cooperative utilities, although many of them also owned plants or shares in plants.

In theory, and absent an overbuild situation, resource-based contracts will bear a price that includes a competitive equity return for the power developer. If market power is present, margins can be much higher. A default service provider might be able to provide lower cost capital for plant development. This is usually true under traditional rate-of-return regulation. For a default service provide in a retail choice setting, this may or may not still be the case. Even if it is not, default service providers should still consider and seek to quantify the risk mitigation benefits of a portfolio containing owned plants. In some cases, plant ownership or resource-based contracts may be the only means to avoid complete dependence on market-based contracts and vulnerability to price swings, market manipulation, and fuel availability. Variables that should be considered in such a decision are discussed in Appendix A.1.

On the plus side, ownership can deliver specific types of resources with characteristics not available from the competitive market. For instance, there has been little development of renewable energy sources in most wholesale electricity markets, despite their environmental and long-term risk benefits. If default service providers, their customers, or their regulators were to value such advantages, one way to obtain them, like any long-term forward asset acquisition, would be to build and own the generating assets directly. Other advantages include escape from market power of suppliers and a chance to sell options or other products to mitigate the mirror image risks that suppliers face, as well as the possibly substantial value of the plant at the end of its financing life, which is often much shorter than the engineering life.

One special benefit of plant ownership is that if the resource has value at the end of the original estimated project life, the utility "owns" it and the remaining life is available to serve consumers without having to pay a second time for the same resource. This value can be considerable, as we have seen many nuclear and fossil plants repowered or refurbished to run much longer than their original financing lives.

In sum, because of its potential benefits to consumers, default service providers should evaluate plant construction and ownership as a possible component to their portfolio. However, ownership clearly adds additional and different risks that must also be managed appropriately. In many retail choice jurisdictions, the transition to competition has resulted in institutional constraints or strong disincentives for plant ownership.[24] Regulators (or legislators) may wish to revisit those limitations.

[24] This is not to say that vertical market power was not an issue that needed to be addressed at the time that divestitures were required.

A Buy vs. Build Example

The fixed (capital related) costs of power from a natural gas combined-cycle plant can vary considerably depending on the ownership type. We consider two possibilities of a plant constructed and owned by (1) a regulated utility or, (2) an independent power producer (merchant plant) who has a long-term contract for the sale of the plant's output. The results are shown in Table 7.2. Detailed assumptions are shown in Appendix A.1.

All other things being equal, we find it is most economical for the regulated utility to build and operate its own generating facility, because it is, in general, the least financially risky of the two options. A regulated utility has lower costs of both equity and debt, because they pose less risk to their investors. A regulated utility can also recover its capital costs over a longer period (typically 30 years) than an independent power producer can, because the utility is subject to less risk of recovering these costs.

Table 7.2. Levelized Price for Electricity under Different Financing Scenarios

	Percent Debt Financing	Percent Equity Financing	Cost of Debt (%)	Cost of Equity (%)	Capital Recovery Period	Capital Recovery Factor	Levelized Price ($/kWh)
Regulated Utility	50%	50%	8	11	30 yrs	10.3%	44.5
Merchant Plant	80%	20%	12	16	20 yrs	13.6%	48.4

7.4 Forward Contracts

In Chapter 4, we reviewed commodity contracts and related financial hedges. Here we will consider how those devices can be used in electric default service portfolio management. Details on these and other contract types are given in Appendix A.4.

Forward contracts are the most traditional of the contractual instruments available for electric PM. They provide for delivery of a specified amount of power at a certain location on the grid at specified times and prices. Such contracts, especially long-term ones, generally handle fuel price through one of three pricing mechanisms:

- *Fixed-price contracts* establish a set price per MWh of delivered electricity or a fixed schedule for those prices. Either way, the price does not vary with market conditions, and the Buyer presumably pays a premium to compensate the Seller for accepting exposure to fuel price risk.
- *Indexed-price contracts* adjust the price of electricity according to either inflation or the cost of another commodity, such as natural gas or oil. (Kahn 1992) These contracts allocate fuel price risk to the Buyer. Forward contracts oblige the Buyer to “take and pay,” regardless of need for the power, so bond rating agencies impose a “debt-equivalent” penalty on the buyer when forward contracts are used.

The penalty is smaller with indexed-price contracts than with other types of forward contracts.[25]

- *Demand and energy contracts* combine the features of the fixed-price and indexed-price contract forms. The Buyer pays a fixed amount for the right to take power and a fixed or indexed charge per kWh taken.
- *Tolling contracts* require the Buyer of the electricity to pay for the cost of the fuel used to generate the electricity (and sometimes other variable operating costs or uncontrollable costs), and the Buyer may also have the option of providing the fuel itself. Tolling agreements and fixed-price agreements conceptualize the service and product being provided by the Seller to the Buyer in fundamentally different ways. In fixed-price contracts, the Seller clearly sells the Buyer a product: electricity. In tolling agreements, the Seller is effectively providing the Buyer a service: the right to use the Seller's power plant to convert fuel to electricity.

Forward contracts are essentially the same instrument as the firm power contracts that have been traded bilaterally among utilities since the first interconnections between them, but those contracts now exist in a somewhat different environment. Since Order 888, they are no longer (usually) FERC-regulated cost based contracts or power pool mediated split-the-savings deals, but "market priced."[26] In many markets, brokers offer a kind of matchmaking service, posting ask and bid prices for standardized blocks of power for various time periods, e.g., monthly for two years and semi-annually for five years, but actual transactions still take place between individual counter-parties. Real future contracts--fully standardized contracts traded anonymously on exchanges that provide regular clearing services--are now available on a number of commodity exchanges around the country for some interchanges.

In general, both long- and short-term forward contracts provide some of the security and stability of utility-owned resources, and warrant consideration for inclusion as a significant part of a default portfolio because these are traits ratepayers value.

Of course, buying forward contracts entails some price risk for the fixed cost portion and also from uncertain demand. Therefore, laddering contracts and diversification of technologies, fuels, and suppliers should be pursued.[27] Careful analysis of load forecasts and price projections should be used to establish a reasonable amount and type of long-

---

[25] Bond debt penalty refers to an adjustment made to the bond rating of a utility based on how much reliance it has on take or pay forward contracts. Rating agencies assign a portion of the fixed cost obligation of the contracts as debt in computing the capital structure of the purchasing utilities in determining the bond rating. (EIA 1994) To the extent that such a penalty is applied, it can eventually result in higher interest costs for the utility and impact distribution rates via the revenue requirement.

[26] As discussed above, the absence of wholesale price regulation does not mean that such contracts are always arm length transactions reflecting efficient free markets. Default service providers, who one way or another, continue to have effectively captive customers should be required to avoid apparent or actual conflicts in trading, especially with affiliates.

[27] Appendix A.1 provides a detailed example of how laddering reduces risk when investing in bonds. The risk mitigation effect can be obtained by laddering power supply contracts.

or short-term forward contracts that should be included. Just as an investment portfolio should avoid too much investment in a single industry or single company, a power portfolio should avoid too much commitment to any specific fuel or generating unit.

In contrast to fossil fuels, renewable resources typically have a less-variable (or even free) fuel cost stream, resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas-generated electricity. Since the use of renewable resources decreases fuel price risk for both parties to a contract, all else equal, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas-generated electricity.

One Disadvantage of Contracts: Contract Disputes and Nonperformance

Physical ownership of generation plant has one particular advantage over both resource- and market-based contracting: performance is in the hands of the interested party—the owner!

A contract dispute is currently taking place in Connecticut. There, market participants are divided on whether federal energy regulators should allow a unit of NRG Energy Inc. to terminate a power-supply contract with Connecticut Light & Power Co. (CLPC). In this case, agreements between the two parties were negotiated before New England divided its power market into eight zones and began determining separate power prices for each zone based on local availability of generation and transmission. NRG gave CLPC only five days notice intent to terminate power-supply agreements, stating that the CLPC had violated the agreement by withholding $20 million in payments related to transmission line congestion in New England. The Federal Energy Regulatory Committee (FERC) had directed NRG to continue upholding the contract for the time being so the commission could make its own decision on the matter. (McNamara 2003)

This type of dispute is an example of why rating agencies assign a risk-penalty to utilities relying on long-term contracts. If the seller becomes insolvent, or the resource becomes uneconomic, the utility is left with either a defaulting provider, or a high-cost resource. If the regulator allows the costs to be passed through to captive customers, it can be recovered, but if customers are not captive, or if the demand does not exist, it can create a difficult situation for the buyer.

7.5 Spot Markets and Trading: Balancing Long and Short Positions

It is common wisdom that the transaction costs of forward contracts and hedging instruments and the risk premia demanded by those who sell them result in extra cost, over the long term, compared to the spot market. After all, the argument goes, markets are efficient at finding the lowest available clearing price, and no one really has a crystal ball clear enough to "beat the market."

So, why not go "100%" short and depend on the spot market for all power? The wisdom of doing so depends on two assumptions that may be interesting theoretical ideals, but certainly do not play a large part in the world-view of successful corporations that trade year in and year out in commodity markets. The first set of assumptions is that markets are perfect: that there is a very large number of buyers and sellers, none of whom have any market power, that there are no information or transaction barriers for purchasers or sellers to enter the market, and that capital is fungible and can immediately be deployed into or out of power generating plants. It is well known that these are not traits of today's wholesale power markets. (Harrington, et al. 2002)

Second, there is an implicit assumption that every buyer and seller has infinitely deep pockets and can wait forever for the "long term" savings of spot market reliance to materialize. In fact, though, even the largest corporations have limits to the losses they can absorb due to market fluctuations and "surprises," so some forms of forward contracting and hedging are an essential part of PM.[28]

On the other hand, going "100% long" is betting the business that one's hunches (or the instantaneous state of the market) are going to be correct. This is especially true if one is contemplating committing to a single forward position all at once for all or most of one's needs, as has been the practice in some default service bidding jurisdictions. Some spot market buying and selling is essential, if only because loads cannot be perfectly predicted hour by hour, and contracts are not available in infinitely divisible sizes. A reasonable portfolio will (aside from hedging instruments to be discussed below) contain a mix of forward positions with maturities of varying lengths and short positions.[29]

Multi-year contracts reduce the volatility of electric prices compared to short-term or annual contracts. Six-month contracts have proved to be only slightly less volatile and costly than spot market pricing. (MAACAP 2001) Fig. 7.1 shows daily clearing prices for peak-period energy at the Cinergy hub for April 15, 2000, through August 2003. Also shown are the prices for the one-year forward contracts for peak period power in 2002 and 2003, as priced by the market during 2001 (for both future years) and 2002 (for 2003 forwards only).

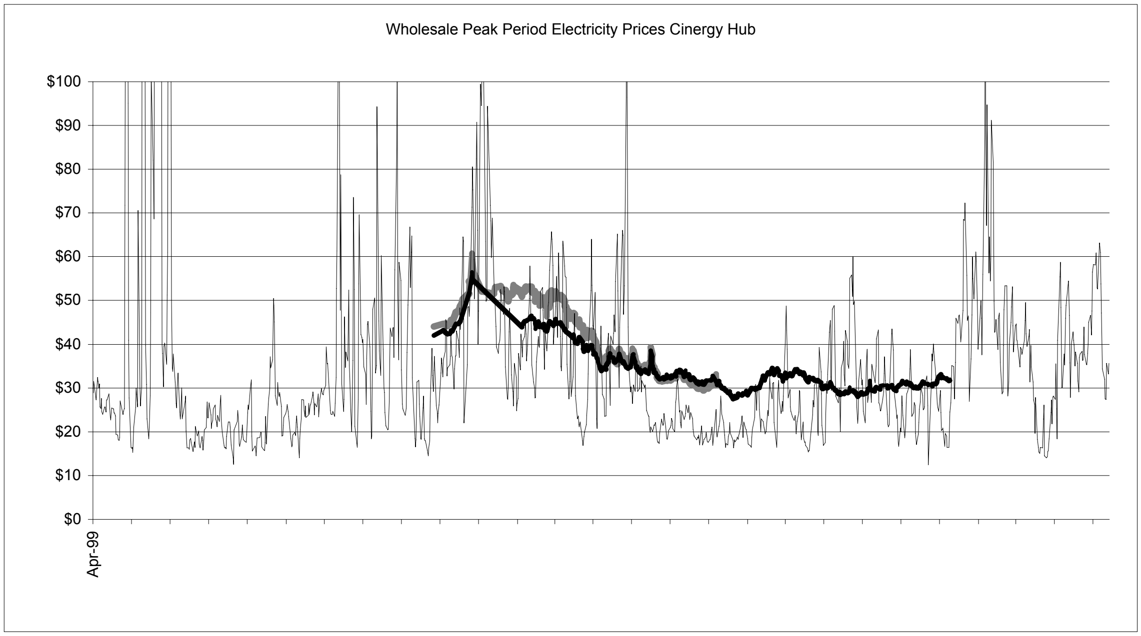
Note, for example, that during 2002 forward contract prices for 2003 delivery were much less volatile than either the 2002 or 2003 spot prices, while during 2001, one-year forward contract prices for delivery in 2002 were less volatile than spot prices during both 2001 and 2002. In this particular period of history, forward contracts bought during the first three quarters of 2001 for delivery during 2002 had an average price greater than the spot price that ultimately prevailed during 2002, while the reverse was true for 2003 futures purchased during 2002. The crucial point, however, is that the one-year forward contracts were less volatile than spot purchases would have been. Combined with laddering, these contracts would have greatly moderated price volatility without the need to "outguess" the market. (It is worth noting that a similar strategy followed during 2000, had forward contracts been available then, would have produced comparable risk reductions during the volatility and price spikes of late 2000 and early 2001.)

---

[28] Serious spot market trading can also require significant investment in staffing and systems. A small amount of spot trading happens automatically under most regional clearing market rules and may be sufficient to handle a small buyer's needs without requiring a large "back room" trading operation.

[29] A short position is an unmet requirement to be met from the spot market as needed, or from advantageous contracts that may become available over time.

Figure 7.1. Wholesale Peak Period Electricity Prices: Cinergy Hub



Not only can portfolio managers reduce their exposure to the price volatility present in the market, but trading of longer term contracts in a given market reduces suppliers' incentive and ability to manipulate prices. If suppliers know that most or all of a buyer's needs are going to be negotiated on a single day or in a single round of acquisitions, they have an incentive and, perhaps, the ability to artificially increase prices on that day through strategic bidding or withholding. Most default service plans are presently negotiated every 6 months to 1 year. Laddering and multi-period contracts may be able to decrease price volatility and market power.

7.6 Risk Management and Hedging

Chapter 4 reviewed the financial hedging instruments that have been developed for various risk management situations. Risk management is, perhaps, the most rapidly evolving aspect of finance today. Virtually every financial institution, including those concerned with commodity trading, are being forced to attend to global risk management due to deregulation, narrowing margins, and increased mobility of capital. (Gleason 2000) The fundamental concepts of global risk management--measuring, controlling and accurately pricing the financial risks they are taking--also apply to portfolio management in an electric industry now subject to many of those same pressures.

There are not as many choices for managing electric resource portfolios as there are in financial markets that benefit from some twenty-five years of maturation. Useful tools for hedging electric supply price risk do exist, however and deserve attention in properly managed portfolios. In any event, just trading forward positions or spot purchases is unlikely to adequately protect either default service customers or the provider's stockholders.

A mix of long- and short-term forward contracts, spot purchases, and, where suitable, resource-based assets can improve PM, reduce risk and volatility for providers and ratepayers, while advancing long-term environmental and renewable energy goals. For example, a default service provider with little retail rate flexibility but operating in a market dominated by gas prices and weather driven price spikes could investigate hedges relying on natural gas or weather derivatives, two derivative industries that are reasonably mature. The Chicago Mercantile Exchange has initiated trading of weather futures and options on a monthly or seasonal basis for each of ten U.S. cities. Natural gas futures and options have been traded on a number of exchanges for some time.

The commodity hedges, derivatives, and swaps discussed so far address the subset of global risk called market risk, i.e., the risk that long positions taken could lose value over time or that the cost of covering short positions could increase over time. Addressing market risk is a substantial challenge in itself, but additional risks can be managed through hedging. A provider whose power is purchased across a national border, e.g., from Canada or Mexico, or is produced from a fuel that is purchased overseas might face currency exchange risk.[30] The robust trade in foreign exchange derivative can be used to control such risks. Some resource-based or system power contracts are indexed to one or another measure of inflation or the cost of money; hedges against such risks are also available.

While the availability and track record of hedging instruments in the electric sector is not extensive, they do exist; cost savings and risk reduction can be achieved through their use. For example, PJM hub futures and options trade on the New York Mercantile Exchange, and Commonwealth Edison and TVA hub products at the Chicago Board of Trade. Reliance on electricity futures and, to the extent they exist, derivatives should be undertaken cautiously until their performance is understood and reliable. The use of derivatives and other hedging mechanisms are subject to special tax and accounting rules and their use requires expertise in these areas.

All affected parties – default service providers, regulators, and advocates – should begin making an effort to learn about risk management and financial derivatives and to prepare for using them as they become available and sound. Default service providers should also engage in sound risk analysis and risk management and act, where appropriate, to encourage the development of viable "markets" for hedging instruments, the more standardized the better. Regulators should encourage and expect such behavior on the part of utilities and default service providers on behalf of consumers who do not have the ability to manage their own portfolios, especially since the retail choice providers have not offered ordinary consumers products with a range of price stability, as was once anticipated. (Harrington, et al., 2002, p. 6)

[30] See, Gleason, 2000, p. 65 ff. Many such "import" situations are under contracts or in markets denominated in U.S. dollars, so this may be a relatively uncommon occurrence, but there have been proposals in the past from generating plants that would have had dedicated, but imported fuel sources, such as Nova Scotia coal or Venezuelan crude.

7.7 Limitations of Hedging Strategies

Earlier in this Chapter, we considered the question of whether it is reasonable to rely 100% on spot purchases or, conversely, to go "100% long" with forward purchases. Our conclusion was that neither course is appropriate for a utility or a default service provider, especially given the current state of wholesale electricity markets and markets for electricity hedging instruments. Some commentators on the industry are suggesting that it is not necessarily for utilities or default service providers to include ownership of renewable generation, physical contracts for renewable generation or energy efficiency in their portfolios, because the same levels of risk mitigation are available through proper use of hedging instruments. This section will examine that notion. While we strongly recommend evaluation and use of financial and other hedging instruments as part of PM, we conclude that the argument for relying solely on those instruments to achieve the consumer goals for PM is misdirected.

First, there are limits to how much risk is diversifiable through adding more and different assets to the portfolio or through hedging. Non-diversifiable risks are those systematic risks that affect all asset prices (in some way). For example, changes in aggregate consumption growth in the economy tend to drive all asset prices in the same direction. (Groppelli and Nikbakht 2000, 90) It is also important to distinguish between financial and business risks. The former are risks that can be quantified and hedged; the latter are those that cannot. (Culp 2001, 26-9, 202) A holistic view of business strategy and tactics needs to be developed for utilities and default service providers taking this into account.

System reliability can be ensured only by genuine physical resources. There are certain power system realities that cannot be avoided or dealt with on paper. Each ISO or control region mandates that physical resources underlie each claimed capability. In most cases, the control authorities physically audit those resources and require them to demonstrate their real generating or transmission capability periodically.

Risk considerations are important in procuring electricity, and it is useful to think of hedging (at least) two types of risk: (a) short term risks (volatility in prices on a daily, monthly, or even annual basis) and (b) long term risks (risks associated with uncertainty about the basic levels of "average" prices over periods longer than a year). For long-term risks, the potential for fossil fuel prices or market supply and demand balances to evolve differently than expected is quite large. (See, for example, Keith, et al., 2003.)

For the short-term risks, forward contracts and various financial instruments can be used to good effect. As mentioned above, hedging instruments bring with them a certain level of counter-party risk—often small for market-traded hedges--that should be evaluated and taken into account. However, it is reasonable to expect currently available products will be supplemented with additional products over time, providing a range of tools for portfolio managers to use in developing a balanced and appropriately hedged portfolio that substantially mitigates short-term price risks. On the other hand, without new physical resources that are independent of the fossil fuel price risk that dominates wholesale electricity markets, these hedges may become unreliable as too many paper hedges chase too few physical hedges. Furthermore, fixed price renewables have been found to have the capacity to greatly reduce prices and price volatility when delivered at peak hours, such as photovoltaics often are. (Marcus and Ruszovan 2000)

For the long-term risks, forward contracts and financial instruments are even less able to do the job on their own without an underlying non-fossil physical resource corresponding to the hedge.[31] Fixed-price gas contracts are only available out about five years and are expensive and thinly traded more than two or three years into the future. Fixed price electricity contracts are available for some hubs on a commodity basis, but for only a few years into the future. Bilateral contracts for gas and electricity can be negotiated at fixed or indexed prices for longer periods, but if not "backed" by an underlying fixed price resource, there is a significant risk of default if market prices rise high enough. Thus, ownership of renewable generating facilities or physically based contracts with sellers who own such facilities is an essential part of a resource portfolio that seeks to effectively hedge long-term risks.

So, hedging long-term risks with purely financial instruments or forward contracts is limited by the (relatively) modest time horizons offered, by immature or thinly traded markets for some of those instruments, and by serious counterparty risks due to the sheer size of the dollar amounts that would need to be hedged. Beyond those issues, there are fundamental limits to how far the economy as a whole can go in offering futures and fixed-price contracts when the underlying technologies have costs that fluctuate significantly. When every firm in the market is seeking to hedge against the same risk, after a certain point, only technologies immune to fuel price risk, such as renewables and efficiency, can underlie hedges for multi-billion dollar risks. Defaults, bankruptcies, and forced renegotiations or abrogation of contracts have all happened and can happen again when firms run out of funds to make good on commitments. Further, hedges are not free, impose risks of their own, and are usually not perfect hedges for the specific risks default service providers face. (Awerbuch 2000)

7.8 Distributed Generation: An Emerging Option

Distributed generation refers to the use of modular electrical generation and storage technologies, and specifically targeted DSM programs strategically sited and operated to supplement central station generation plants and the T&D grid. On the "supply side" of the concept, relevant technologies include small-scale internal combustion engine-generator sets, small gas turbine generators and microturbines, energy storage systems, photovoltaics, wind generation, and fuel cells.[32] The potential benefits include avoiding

---

[31] It might be suggested that nuclear and coal generation can supply fill this gap as well or better than renewables. We doubt it; those resources are correlated with and subject to many of the same risks as gas or oil generation. Coal prices are not independent of oil and gas prices and are subject to the same regulatory and environmental risks, as well as their own major technology risks.

[32] Wind generation offers many of the same benefits--modularity, ability to provide dispersed voltage support, fossil fuel and air emissions risk reduction, power closer to remote loads, etc. However, since DUP often driven by potential benefits for solving local T&D peak loading and capacity constraint problems, non-dispatchable technologies (or, at least, those that are not constant), wind as a distributed generation technology requires special consideration.

or deferring T&D upgrades; improving power quality; lower T&D losses; and, given the shorter lead times and the modularity of the technologies involved, reduced risk of costly generation and T&D over-capacity by more closely matching electrical supply to demand. (Vt. DPS 2003) Distributed generation benefits are discussed further in Chapter 8. Distributed generation technology characteristics relevant to PM are summarized in Appendix C.

Default service providers, if institutional and regulatory structures are supportive, can acquire significant environmental and economic development benefits for society while reducing portfolio cost and managing portfolio risk by carefully selected, planned, and implemented DG use. However, few electric utilities have fully embraced DUP due to a number of significant barriers, including the dispersion of benefits, incompatible regulatory structures, and the changes and distractions accompanying industry restructuring. Appropriate new regulatory policies, mentioned briefly in Chapter 11, will be needed to enable acquisition of those benefits.

8. Evaluating Transmission and Distribution Options

8.1 Transmission and Distribution in Portfolio Management

Traditional integrated resource planning (IRP) calls for utility planning to meet forecasted power needs through the combination of adequate, safe, and reliable generation, transmission, distribution, and demand-side resources that has the lowest life-cycle cost including the costs of environmental impacts. Transmission and distribution resources in such a plan serve both reliability and power requirements. Some generation resources may require the addition of transmission capacity so power can be delivered to load centers or exported. Alternatively, access to wholesale power markets may require additions to transmission capacity. If the selected portfolio seeks to meet growing power needs through central station generation or market purchases, distribution upgrades may also be needed. Conversely, to the extent that a portfolio will meet needs through distributed generation or demand-side management, less investment will be needed in T&D. In any portfolio, some T&D investment is likely to be required over time to replace plant that is deteriorated or to meet reliability requirements.

T&D resource needs may be thought of as driven by one or more of three forces: (1) engineering reliability requirements, (2) a need to deliver power to or from generators and markets, or (3) economic opportunities deriving from geographic differentials in power costs. Often, a T&D option will advance more than one of these categories. T&D investments should be evaluated in comparison with distributed resource alternatives (described below) as well as generation options of all types.

T&D construction sometimes faces significant permitting and siting challenges. Other factors in T&D upgrades include high fixed costs, lumpiness, land use and aesthetic impacts, electrical losses incurred, and a need for technically sophisticated engineering analysis and design, especially at higher voltages or if DC transmission is involved. T&D upgrades usually have low annual operating costs (if constructed by the user) or relatively high annual usage charges (if acquired from another entity). T&D additions or upgrades can either raise or lower line losses or create engineering problems for existing systems, depending on the system. To address these complexities, high-voltage transmission additions or upgrades located in or connecting to a power pool, ISO or RTO will usually require detailed engineering studies and pre-approval before interconnection.

Portfolio managers should consider not only the generation resources that are available with the existing transmission system, but also those that could be tapped via new or upgraded transmission. Conversely, evaluation of generation resources should reflect the costs, engineering and permitting requirements, and impacts of transmission required to bring the power to consumers. The line loss and reliability side benefits of transmission investments may be significant, and option value may be added through access to additional markets or varieties of generators. Some of these costs and benefits also apply to distribution investments.

In the case of vertically integrated utilities, T&D resources and distributed resource alternatives should be considered at all levels of the grid from local distribution feeders through subtransmission to bulk transmission properly coordinated with ISO's or other regional entities, as needed.[33] Where there has been disaggregation, but default service is still provided by the distribution-owning utility, the situation is more complex, but the goal should be the same. Some T&D upgrade options and most or all distributed resource alternatives will be within the scope of planning and action of the default service provider.[34] Coordination with ISO's or other regional entities can provide distribution only utilities a forum for exploring bulk transmission resources as a part of portfolio management.

Finally, if default service is delivered by a non-utility entity under bidding or other arrangements, it may be difficult to position the default service provider to evaluate or plan either T&D investments or distributed resource planning and acquisition. If those activities are to be undertaken successfully, they may need to be a function of facility-based utilities or regulators with implementation of non-generation alternatives placed appropriately. In all three of these service environments, regulators should carefully design rates, incentives, planning requirements and related activities to provide clearly assigned responsibilities and expectations regarding the identification, planning, and delivery of T&D and distributed resource alternatives as part of default service PM.

8.2 Distributed Utility Planning Concepts

Distributed utility planning (DUP) is a generalization of IRP as it was developed over the past fifteen years or so. IRPs twin notions of minimizing life cycle societal costs and an even playing field for all supply-side and demand-side resources made no particular distinction, at least in principle, between T&D options and other available resources. (NARUC 1988) As DSM programs matured and proved themselves, it became clear that DSM could cost-effectively defer or eliminate the need for T&D upgrades in certain situations, especially where there upgrade was being driven by a projected capacity constraint and reasonable lead time was available. Sometimes, a partial T&D upgrade and a DSM program can be combined to meet resource needs for many years.

In the second half of the 1990s, as wholesale electric market competition became a reality and many jurisdictions disaggregated vertically integrated utilities, it became apparent

---

[33] As discussed above in Chapter 7 for generation assets, some service territories are dealing with transition issues for pre-existing ownership of transmission assets, ranging from total divestiture to continued ownership of legacy assets. These situations are further complicated by the fluid state of transmission ownership, operation and pricing as FERC and the regions grapple with emerging ISOs, ITCs, and RTOs. Additional complexities are introduced where such legacy assets are owned by corporate affiliates, although FERC Orders 888, 888-a and 2000 provide for some separation, at least regarding system operation. Regulators should ensure default service providers deal effectively and in a least cost manner with any legacy transmission assets, imposing appropriate codes of conduct and rules for affiliate transactions where needed.

[34] Larger DG options or those interconnecting at high voltages may require coordination with or approvals from transmission owners, ISO's or other regional entities responsible for interconnection standards.

that opportunities for savings in integrated planning of distributed alternatives to both T&D upgrades and generation needed special attention to avoid a loss of focus and momentum. At the same time, advances in small-scale generation technologies, such as micro-turbines and sold-state interconnect devices, and improvements in the cost and efficiency of renewable generators brought the option of small, dispersed generation to the fore. As a result of this tension, a renewed focus on such concepts arose under the rubric of distributed utility planning or "DUP."[35]

DUP is best viewed as an ongoing, cyclical planning process including the following steps.

1. Identification of areas with existing or projected T&D supply problems.
2. Definition of the region in which load reductions would be reasonable to help defer or avoid the T&D reinforcement or reduce its cost.
3. Identification of deferrable costs and the load reductions that would be needed to defer those costs for various periods of time.
4. Determination of the benefits of DSM load reductions in the form of revenue requirements, societal costs, and risk reduction.
5. Development of targeted DSM and DG programs to relieve congestion.
6. Estimation of non-T&D side benefits from DSM and DG load reductions.
7. Selection among the available options based on minimizing net societal costs.
8. Implementation planning.

While T&D reliability standards and institutional arrangements for planning and implementing improvements differ, DUP is equally applicable at all voltage levels. It is directly applicable to T&D capacity constraints and, to some extent, to reliability issues not driven by capacity constraints. However, DUP is also relevant to portfolio management for default service by virtue of the risk management benefits and option value it can deliver. To realize these benefits in the context of default service provision, it is necessary for regulators or state governments to provide an institutional structure that bridges any gaps in the integration of resource planning created by the institutional structure chosen for delivery of default service. The critical points are (1) to put DUP in place as a fully-functioning activity of facility-owning utilities and (2) to create a mechanism to include in DUP decision-making the benefits and costs available to default service portfolio management from distributed resource alternatives.

8.3 Distributed Utility Planning Policy Issues

DUP faces regulatory and institutional barriers. Among these are the fact that benefits are dispersed and incompatible regulatory structures at both state and ISO levels.[36] In

[35] See, for example, David Moskowitz et al. 2000.

[36] The following paragraphs rely heavily on work by the Vt. Department of Public Service, *op. cit*.

deploying a distributed resource installation, there is often a kind of inverse commons effect: some of the benefit will accrue to the owner of that installation, but the remainder will flow to others, including retail customers, upstream transmission entities, and the public.

> "Consider, for example, the hypothetical installation of a fuel cell at the site of an electronics manufacturer located on a constrained distribution feeder. Benefits to the manufacturer from this installation include premium quality power, enhanced reliability, and process heat. Benefits to the distribution utility serving this manufacturer are voltage support and the deferral of feeder upgrades. The general public benefits from reduced air emissions and avoided postage stamp T&D rate increases. The default service provider (which may be the distribution utility or may be a third party) involved benefits from increased interaction with its customer and lower supply risk. From a societal perspective, the sum of all of these benefits, depending on the situation, could exceed the incremental cost of the fuel cell over the cost of conventional options. At the same time, no single set of benefits is large enough to entice any one entity to ultimately own and install the unit. Hence, a market failure results." (VT DPS 2003)

Regulatory policies such as performance-based rates, emission credit trading systems, tax incentives, streamlined permitting or subsidies could help overcome these barriers. Where applicable, regulatory directives, incentives, and cost-recovery mechanisms may be useful. The presence of retail choice and accompanying divestiture mandates require special provisions if artificial barriers to distributed generation development by distribution utilities, whether or not they provide default service, are to be surmounted.

9. Determining the Optimal Resource Portfolio

Establish Objectives for Determining the Optimal Resource Portfolio

In order to make decisions and trade-offs between the many different types of electricity resources available, it is necessary to establish clearly-defined objectives. These objectives should be developed through an inclusive public process involving the many stakeholders in the electricity industry, in order to ensure that the objectives reflect the needs of affected parties and the lessons learned from recent experiences in the electricity industry. Regulators must ensure that portfolio managers apply these objectives appropriately in developing their resource portfolios.

Some of the key objectives of portfolio management are the following:

- Provide safe and reliable electricity services, at the distribution, transmission, and generation levels for all customer groups.
- Minimize electricity bills, for all customer types.
- Charge stable electricity rates over the short- and long-term.
- Reduce the risks associated with electricity services and prices, including the risks associated with price volatility, uncertainty, financial risks, and the risks due to future environmental regulations and reliability.
- Implement a diverse and balanced set of electricity resources, including (as appropriate to the situation) various fuel types, technology types, contract terms, and financial hedging instruments.
- Improve the efficiency of the electricity system, with regard to customer end-use efficiency and the efficiency of the generation, transmission, and distribution systems.
- Maintain equity across customers.
- Ensure that all customers can benefit from positive developments in the wholesale electricity markets.
- Mitigate the environmental impacts of electricity resources.

Consider All Resource Options

Sound portfolio design begins with load forecasting and a review of the planning environment in terms of strengths and weaknesses of existing resources, economic and technological trends, and strategic threats and opportunities. Next, a portfolio – temporarily limited to physical generation assets and forward contracts, plus any required T&D additions or upgrades – should then be assembled that provides an adequate, safe, reliable, and environmentally sound power supply at the lowest life-cycle present value cost.[37]

All reasonable resource options should be considered. Supply options that should be considered include conventional generation plants, renewable or evolving technology generating plants, resource- and market-based contracts, life extension and repowering, and T&D investments that make additional supply sources accessible or reduce line losses or capacity requirements.[38] All resources must be evaluated even handedly, counting costs for capital, operating, fuel, maintenance, ancillary services, environmental compliance, permitting and decommissioning.[39]

The next step is to examine alternatives to generation: methods for controlling and moderating demand, such as energy efficiency savings, DUP options (both DSM and DG), transmission upgrades or additions, load control and load response programs. This step must begin with a thorough knowledge of the purposes to which each customer class puts electric consumption, the efficiency levels of those end uses, and the costs and savings of the full range of measures and programs available to modify that demand.

The cost-effectiveness of these alternatives is then evaluated. One means is to screen them by comparing efficiency measure costs to the generation and T&D costs (both capital and operating) avoided by them (including reductions in T&D losses and reserve requirements). Special attention should be paid to measures that save power at times when loads are highest. Cost-effective DSM and DG measures incorporated into the portfolio to the extent they can cost-effectively displace or defer supply-only options. (NARUC 1988)

Address Risk

Many jurisdictions and utilities conducted integrated resource planning in a least-cost analytical mode, with risk management treated as a supplementary exercise, and the required reliability level treated as a given. Given today's sweeping and ongoing market changes, it is prudent to place greater emphasis on treatment of uncertainty and risk issues in portfolio management.

Risk management alternatives can be evaluated in terms of the degree of volatility removed, their implementation cost, and/or their susceptibility to regulatory scrutiny. Specific types of risks facing the electricity market include:

- Fuel price risk.

[37] Each jurisdiction must consider what definition of cost it finds most appropriate. The various options for this definition were discussed in Section 7 of this report.

[38] Generation capacity requirements are sometimes driven not by the need to serve energy or peak load, but by reliability concerns. In effect, capacity is sometimes required to protect against T&D or generating outages. In many situations, T&D improvements or smaller, more modular generating plants can reduce the need for generating capacity.

[39] A system dispatch model should be used that treats plant outages probabilistic loss of load computations, not by simple derating. This is essential not only for accuracy, but so that the reliability benefits of intermittent resources may be captured correctly. (Lazar 1993)

- Fuel availability risk.
- Uncertain ability to balance supply and demand of electricity.
- Transmission congestion costs.
- Environmental compliance costs.
- Environmental operating restrictions.
- Ancillary service costs.
- Credit risk.
- Uncertain availability of resources – including demand side management and distributed generation.
- Electricity market structure uncertainty.

From a generator's point of view, high volatility and risk are important in terms of stable revenue streams and in terms of determining the worthiness of new investments; investors have a hard time determining whether current prices indicate long-term values or transient events. From a residential or industrial consumer's perspective, electricity price risks can have a direct effect on consumer wealth, as well as on the ability of consumers to budget their expenses and make financial plans.

There are several means of addressing risk in the development on the optimal portfolio. The first means is in the selection of supply-side and demand-side resources themselves. If the least-cost portfolio is overly sensitive to uncertainties in load, market prices for fuels or wholesale power, or environmental risks, then modifications are needed to the portfolio to protect against these uncertainties. In general, portfolio optimization using energy efficiency and renewable resources will be able to deliver reduced risk at the same cost as the initial portfolio, or lower cost with the same risk, or a combination of the two. (Awerbuch 2000) Also, if a portfolio results in inappropriate costs for some classes of customers or places them at higher risk than others, further changes may be needed.[40]

The second means of addressing risk in the development of the optimal portfolio is through the use of financial hedging methods that can further reduce cost and risk. Portfolio managers should examine how the more complex financial and power transactions can augment a traditional least-cost portfolio of generation, T&D, and DSM assets to further mitigate risk and reduce cost. It is important to note that, without a sound resource plan that accounts for risk through the choice of supply-side and demand-side resources, hedging will simply increase the cost (hedging is not free) and reduce the variability of a portfolio that is more expensive and riskier to rate payers and society than it needs to be. (Bolinger, et al. 2003)

Finally, portfolio managers need to analyze the risks associated with candidate portfolios, using techniques that explicitly capture the variability and uncertainties associated with long-term resource planning. There are a variety of techniques that seek to quantify the uncertainties associated with a given portfolio, so that alternative portfolios may be

[40] For example, the base case may include a major expansion for a very large commercial or industrial customer that requires significant new power supply and T&D commitments if it is to be met at the lowest expected. However, if that expansion is uncertain, smaller rate payers are placed at risk, and alternative measures that reduce the size of the new commitments needed, or have shorter lead times so they can be deployed if and when the additional load develops, may be more appropriate.

compared on both cost and uncertainty. Some of these methods also help to identify the components of a portfolio or the environmental variables that contribute most to that uncertainty. This can be helpful in designing improved portfolios. The choice of risk management techniques include several types of stress testing or scenario testing, mark-to market, computer simulations, decision tree analysis, and real option analysis. These techniques are described further in Appendix D. The rest of this subsection reviews the overall approach to measuring and comparing portfolio risks.

When comparing electricity portfolios, we would like to be able to quantify and compare the risk of each portfolio. Similarly, when issuing an RFP for electricity supply, we would like to be able to specify a desired quantitative level of risk and to compare riskiness (to consumers) of bids.[41] To illustrate this process, we will consider two types of risk: price volatility and counter-party risk.

Price volatility can be assessed quantitatively for each resource and the portfolio as a whole in terms of the standard deviation of the price. For fixed price contracts, this is zero. For many renewables, the variable cost is zero, but the total cost depends on the kWh output. If the output's variability is known, the price variability can be computed.

Counter-party risk is more challenging to quantify. Doing so requires an assessment of the sources of such risk, the probabilities of those risks materializing, and the price impact if they do. For example, in the case of a contract for the output of a specific power plant, one counter-party risk is always vendor bankruptcy. In bankruptcy, the vendor can reject the contract.[42] Assessing the probability of bankruptcy for a particular vendor is difficult, but may be informed by the vendor's bond rating and leverage as shown in its audited financial statements, if available, as well as the nature of the resources physical or otherwise, on which the vendor relies.[43] Finally, using these probabilities and an estimate of replacement power cost, the increment of variability that counter-party risk will contribute to the overall variability of the contract can be estimated.

Not all risks can be quantified reliably, if only because historical data are lacking or future performance cannot be relied on to replicate history. In such cases, qualitative assessments, such as management audits, may need to be relied on. In other cases, such

---

41 It is important to keep in mind that risk is a property of *both* an entire portfolio *and* the portfolio's component parts. That is to say, each resource in the portfolio will have its own level of volatility, counter-party risk, and so on, but the overall riskiness of the portfolio is *not* a linear sum of those risks. Consider a portfolio with two components, both owned by the utility so there is no counter-party risk: a 400 MW gas combined cycle power plant and a 400 MW oil-fired steam plant, with any shortfall in output to be made up at a market price dominated by gas-fired generation at the margin. The two generating plants each have certain risk of forced outages, price volatility, and regulatory risks due to possible new emissions standards. Since the two plants are physically separate, the portfolio has lower *average* forced outage risk than either plant separately. Since they are different technologies, the same is true of environmental risks; for example the gas unit would likely be affected less by new SO_2 restrictions than the oil unit. Depending on how closely correlated gas and oil prices are, the cost of the overall portfolio may or may not be less volatile than the cost of the individual plants.

42 Other possibilities, such as a renegotiation of the contract, can be analyzed in a similar manner.

43 Relatively recent credit scoring methodologies used in the finance industry may be of use here. See for example, Gleason 2000, p. 167 ff.

as analyzing risks of additional environmental regulation, estimates of the likely costs of compliance with new regulations can be applied.

Portfolio managers should begin by emphasizing orderly risk identification and data collection. Historical data on resource availability and price volatility of key cost inputs should be available for most resources. We recommend starting with careful estimation of portfolio price variability, as described above, taking into account at least these factors, plus careful qualitative evaluation of other risks. Such an assessment should include careful analysis of the degree to which the risks affecting the cost and performance of the underlying physical resources are congruent with the guarantees made by vendors, if any. Some portfolio managers and regulators may wish to add quantification of probabilities and price consequences of the most salient counter-party and regulatory risks affecting the most important portfolio components.

Service providers or regulators issuing RFPs for power to supply monopoly or default service customers should require provision of the necessary data (under seal if necessary) for such analysis. Experience does not permit drafting at this time of RFPs that establish a specified level of risk to be delivered, and the lack of experience in doing so would likely discourage bidders from participating in a solicitation that did so. In competitive solicitations, regulators should instead specify that selection will be based on both price and some defined measure of risk, such as that given above, with some weighting.

10. Maintaining an Optimal Resource Portfolio over Time

10.1 On-going Portfolio Management

Once an optimal resource plan has been determined, the utility needs to implement the plan flexibly and judiciously. Ongoing evaluation and updating not only help realize the potential of PM and risk management, but assist in coping with and responding to the unexpected.

One reason flexible portfolio options are beneficial is because they create an ability for the portfolio manager to make adjustments over time as uncertain future developments solidify and new opportunities or uncertainties arise. To reap those benefits, the portfolio manager must continuously monitor the environmental factors that could impact cost effectiveness and risk, investigate and evaluate new resources and opportunities to add value to the portfolio or reduce risk, assess the actual performance of portfolio components against their expected performance and, generally, act diligently to maintain the integrity of the portfolio and adjust to ongoing developments. (Culp 2001, 485 ff.)

To ensure that the portfolio strategy is successfully implemented, an action plan should be prepared that covers acquisition and disposal of portfolio elements; monitoring of market conditions, environmental trends, electric loads and end uses; checks portfolio performance; and seeks out and evaluates potential acquisitions or hedging instruments. Counterparty credit and settlement risk require constant attention.[44] Both supply and demand side initiatives should be evaluated on a regular basis. The action plan should provide for scheduled reviews and updates of goals, assumptions, and strategies.[45]

For any portfolio, especially one containing medium- or long-term forward contracts or hedges, it is important to routinely assess risk exposure as part of performance monitoring. The market risks of most interest to portfolio managers are wholesale power prices, fuel prices, and electricity demand. Credit risks (counterparty settlement risk, primarily), operational risk (owned plant performance, for example), legal risk (contract disputes), regulatory risk (FERC market rule changes), and event risk (war, natural

---

[44] In many forward contract markets for power and gas today, *sellers* or market rules require costly credit guarantees from *buyers*, even fully regulated utilities. Conversely, default service providers and utilities must follow the financial health of major counterparties carefully. The NRG contract dispute, described in Section 7.4 above, is just one example of how serious this issue can be.

[45] Despite these cautions about maintaining a dynamic, continuously evaluated and adjusted portfolio, it is also important to provide a reasonably stable budgetary and institutional environment for long term projects. In particular, DSM and DG programs require lengthy implementation periods to bear fruit, and an unstable operational environment will doom them to failure. Many renewable energy projects are so capital intensive that long term commitments are necessary so they can attract appropriate financing. Modular design and careful, ongoing process evaluation offer opportunities for dynamic PM, while still providing the kind of stable environment these resources need to mature.

disaster, political events) may also be important. Tools for exposure assessment are discussed in Appendix D.

10.2 Procurement of Resources

In addition to action planning and plan updating, a default service provider will need, at some level, to engage in plan implementation: actually buying and selling power and hedging instruments and acquiring DSM and DG resources, as called for in those plans. It is beyond the scope of this paper to explore fully the management of each of these functions, but we will indicate the key elements necessary for successful procurement of each category.

At the outset, it is worth pointing out one longstanding concern with the management and staffing of non-traditional generation assets. Proper *integration* of each function (and staff carrying it out) with a coordinated enterprise-wide effort requires solid commitment from and ongoing follow through by top management. It is also hard, but necessary, to ensure *parity* of these functions within the firm. Generation and T&D ownership are the traditional roles of utilities, and supply planning units are often led by engineers who are more technically oriented and less customer oriented than those involved in DSM or DG work. Trading of contracts and hedges may be done by personnel or even located in units that come from an accounting or finance background. Some functions may be outsourced. Each of these situations flows from natural historical developments and, indeed, responds to very real job requirements. But it is up to top management to ensure that decisions *between* these alternatives are based on sound communication and rational priorities. (NARUC 1988, 16; Gleason 2000, 221 ff.)

Perhaps the best understood of these procurement functions is the construction and operation of conventional power plants. Even here, it is important examine the way in which these decisions flow from and react to PM decisions. Construction planning should maximize flexibility so that work can be slowed, canceled, or accelerated and, if possible, so that capacity can be increased or decreased. Those decisions also need to be managed to maximize value and minimize risk. (Trigeorgis 1996)[46] Operations of combustion generators will also entail a variety of cost minimization and risk management tasks not least of which is application of the entire repertoire of PM techniques to fuel supply and arrangements for the sale of any temporary or seasonal excess power.

Developing or purchasing physical generation or resource-based contracts for renewable energy adds new challenges to the implementation requirements for traditional power plants. Most relevant renewable technologies are evolving rather than mature, while utilities, regulators, local residents, and other stakeholders are less familiar with the issues and benefits.

---

[46] Ownership structures can impact this issue. On the one hand, a partial ownership (or contract rights) to several power plants under construction provides some risk protection compared to sole ownership of a single unit. On the other hand, lead or sole owners have much more ability to manage projects to suit their needs. Each project needs to be considered from both perspectives.

As mentioned above, procurement and management of long- and short-term forward contracts may require the creation of what is essentially a commodities trading operation, which can require substantial investment and lead time to develop and prove itself. Hedging operations are even more complex. The learning curve for both can be quite steep and mistakes costly. (See Gleason 2000, generally, for examples.) One alternative is outsourcing of procurement. As indicated in the box below, Green Mountain Power has used this approach. The appearance of "structured products," where an investment bank or other commodity risk taker provides all or part of a commodity portfolio could be considered, although the cost premium can be quite high.

Outsourcing Supply Portfolio Management

Green Mountain Power Corporation (GMP) sells electricity and energy services and products to about one-fourth of Vermont's retail electricity customers. GMP also sells electric power at wholesale in New England and sells operations services to other utilities in Vermont. The company has a risk management program that has an objective of stabilizing cash flow and earnings by minimizing power supply risks due to such things as risk of fossil fuel and spot market electricity price increases.

Specifically, the company initiated a contract to outsource its power procurement responsibilities to Morgan Stanley Capital Group, Inc. ("MS"). As of February 1999, MS began purchasing the majority of the Company's power supply resources at indexed prices (for fossil fuel-fired plants) or at specified prices (for contracted sources), while selling to GMP at a fixed rate to serve pre-established load requirements. More specifically, on a daily basis, and at MS's discretion, GMP sells power to MS from either its own power resources or those available to it. MS then sells to GMP sufficient power to serve pre-established load requirements, all at a predefined price. MS is also responsible for scheduling supply resources. This contract, along with other power supply commitments, allows the Company to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The MS contract is effective through 2006. It saved the Company an estimated $4 to $5 million during 2000 alone. (Dutton 2002)

To date under this contract, the Company's retail rates have remained below the average of all major electric utilities in New England. (Green Mountain Power 2003) For the remaining life of the contract, the volume of transactions under the contract will be modified. GMP will take back contracts representing the majority of its committed supply, namely contracts with HQ and Entergy; these contracts have very stable pricing, so the risk reduction from handing these contracts to MS to manage is not worth the cost. There will continue to be some volume of power, based on fossil-fired units and estimated at $6 million per year, handled under the contract. (Sedano 2003)

More importantly, hedging and commodities trading are outside the experience of many electric utilities and their regulators. Where they are familiar activities, it is usually in the context of either purchasing generator fuel or for retail gas utilities. Certainly, well-defined rules need to be developed for such activities to protect consumers from ill-considered speculation.

Procurement and ongoing management of DSM resources is less novel, but still requires careful oversight. Program planners and managers must have access to expertise about cutting edge technologies in a wide variety of end uses from residential lighting to building shells and HVAC controls, types of engineering not usually in the skill set of traditional utilities. Energy efficiency is only one aspect of a building or manufacturing process, and will often need to be marketed as a set of coordinated benefits to the end user. (Sedano 1998).

DSM action plans should provide adequate resources, including knowledgeable staff, for program design and marketing, either directly or through contractors, for such functions as direct customer marketing, interface with trade allies, public education on energy efficiency programs, and branding. As part of its program management responsibility, the utility should collect, manage and analyze tracking data on participating customers, trade allies, and general program operation and regularly report to management, regulators and the public, make ongoing adjustments to program operation based on tracking and monitoring. (VT DPS 1997, 84 ff.)

Finally, it is worth mentioning that ongoing information gathering should be an integral part of any PM implementation plan. Pilot programs, R&D tracking, and competitive intelligence gathering and analysis are a few of kinds of information gathering that will assist in keeping a PM strategy alive and functioning.

10.3 Flexible Application of PM

The most effective approach to PM is likely to vary with the regulatory and competitive situation of each jurisdiction. After the restructuring wave of the 1990s, the regulatory landscape is much more varied than it formerly had been. Not only are some states restructured and some not, but those that have restructured addressed default service and transitional arrangements differently. However, there are three main categories into which states fall:

1. Retail competition with competitive acquisition of default service;
2. Retail competition with default service by the (disaggregated) distribution company; and
3. Fully regulated retail service by vertically integrated companies.

Though the goals are the same, PM is a somewhat different process for states in each category. (Harrington, et al., 2002, 19 ff.) In the broadest terms, states in categories 2 and 3 need only import into their existing oversight expectations for utilities to use PM for the benefit of ratepayers. In some states, the certain restrictions were imposed on the utility's default service activities that may interfere with sound PM; such restrictions may need to be modified. California's prohibition of forward contracts is the classic example. In category 1, the regulator supervising the competition could, in principle, develop bidding specifications and performance criteria that would require sound PM and flow the benefits to ratepayers.

In each of these categories, however, there remains to be developed practical ways and means for regulators to implement these goals. For example, a regulator would benefit from a rule or formula that would compute the proper target degree of uncertainty or variance in expected retail price for default service. Unfortunately, such rules are unlikely to be available and would likely need to be adapted for each state's situation and available alternatives. Best practices should be developed for default service PM, but even they would need to be revised over time as new hedging products become available and PM understanding progresses.

One challenge facing regulators who seek to promote sound PM will be the complexity of the data and methodological issues that would have to be addressed in a rule making or litigated case to establish PM requirements and standards. Similar difficulties were faced and overcome in the initiation of IRP requirements in the early 1990s. In addition, some commissions found that the periodic dockets for review and approval of IRPs were challenging. This risk needs to be addressed, but should not deter regulators from pursuing PM requirements and oversight. Rather, experience developed over the past decade in collaborative rulemaking and collaborative settlement processes for litigated cases should give some confidence that these complex matters can be addressed reasonably and expediently for the benefit of consumers. In addition, commissions may avail themselves of the extensive case management tools developed in anti-trust and mass tort litigation, which go under the rubric of complex case management. (See, for example, Fed. R. Civ. P. 16(c)(12) and Federal Judicial Center 1995.)

11. Regulatory and Policy Issues

It has become clear from the experience with electricity industry restructuring to date that default service providers must play an active role in managing generation services to retail customers. Default service providers will be serving the vast majority of electricity customers well into the foreseeable future, and they continue to have an obligation to provide reliable electricity services at just and reasonable rates to these customers. For utilities not subject to restructuring, these roles have not been changed, but the tools available to improve the quality of their electricity services have evolved.

It has also become clear that all electric utilities – vertically-integrated and distribution-only – must take greater care in managing resource portfolios. The recent developments in the competitive wholesale electricity markets create greater opportunities but also greater pitfalls. A passive or inactive utility is more likely to suffer from the pitfalls than benefit from the new opportunities.

It is also clear that regulatory guidance and oversight will be critical to achieve the goals of portfolio management, and to ensure that all utilities have clear direction regarding their roles as portfolio managers. Many utilities in states with restructured electricity industries have been acting as though they have a lesser obligation to manage resource portfolios than in the past, in part as a result of the explicit or implicit policies and directives from regulatory commissions. This trend must be reversed in order to ensure that electricity customers are well served, that the market provides benefits to all customers, and that neither consumers nor utility shareholders are exposed to the kind of radical volatility that affected California in 2000-2001.

On a practical note, in any regulatory setting, decision makers will need to address factors that go beyond the data and theory of portfolio management. Political realities, regional priorities and preferences, land use impacts of various resource options, availability of utility and commission resources and skill sets, institutional constraints and histories, and authorizing legislation, all impact not only how portfolio management should be done, but whether and when it can be implemented in regulation. Furthermore, the technical analysis and managerial decision making necessary to plan and implement portfolio management requires not only theoretical knowledge, but also a thorough grasp of the context in which the plan will be carried out, including jurisdictional priorities and preferences. Experience and knowledge matter in making these decisions. Initial conditions, too, will have a strong influence on proper portfolio management due to the long-lived nature of the resources that underlie existing portfolios and the markets in which new resources can be acquired. Oversight and management of portfolio management planning and implementation will be critical to control the risks that arise from those decisions.

While a complete discussion of the policies necessary to support portfolio management is beyond the scope if this report, we list a few key areas that require attention from legislators, regulators and other stakeholders in the industry.

- *Clarify the objectives*. In states that have allowed retail competition, regulators need to explicitly require utilities or non-utility default service providers to be more active with portfolio management and to adopt portfolio management techniques. In states that have not allowed retail competition, regulators still need to clarify utilities' responsibilities regarding portfolio management in light of the uncertainties associated with regulatory and market changes in recent years.
- *Provide periodic regulatory review*. Successful portfolio management will require regulatory guidance and oversight on an on-going basis. This requires that regulators periodically review and assess the decisions and the actions of portfolio managers, whether the jurisdiction operates with pre-approval, ex post review, or both.[47] The traditional IRP process is a good basis and venue for this type of review. Experience in several states, most notably Nevada, shows that ex-post review can produce very painful results for utilities.
- *Provide guidance on risk management.* There is a need for legislators and utility regulators to provide guidance on expectations about the risk management responsibilities of default service providers, whether integrated utilities, distribution companies, or other types of default service providers. Guidance on the level of risk appropriate for default service portfolios would be valuable to inform the development of appropriate mixes of types of resources and the duration of commitment to those resources. At a minimum, default service providers should be required to address their strategies and performance in portfolio plans, integrated resource plans, bids, or other processes. Since this is a novel task for regulators and the utility industry, further research on methods for establishing and achieving risk management goals should be pursued.
- *Allow stakeholder input to the process*. One of the more challenging aspects of portfolio management is in balancing the many different criteria for selecting the optimal resource portfolio. This balancing act often involves trade-offs that affect different stakeholders differently. In order to ensure proper balancing of the array of interests, it is important to allow the various stakeholders to provide input into the portfolio management process. Adequate participant funding is another essential element to ensure stakeholder participation.
- *Provide utilities with appropriate financial incentives*. Utilities cannot be expected to adopt portfolio management processes or implement resource portfolios that result in negative financial consequences for the company. Regulators must ensure that ratemaking and restructuring policies will promote sound portfolio management practices and discourage inaction or improper management practices. Regulators should ensure that existing policies – such as performance-based ratemaking mechanisms – support and do not hinder portfolio management practices.

[47] Even under pre-approval regimes, implementation must still be monitored, if only to identify changes in policy that are needed.

- *Provide appropriate incentives for energy efficiency activities*. Electric utilities face significant financial barriers to implementing energy efficiency programs. Under traditional ratemaking approaches, efficiency savings result in lost sales, which can result in lost profits between rate cases. If legislators and regulators designate electric utilities as the primary entity to plan for and implement energy efficiency programs, then it is essential that ratemaking policies be designed to overcome this financial barrier. The most effective approach is to decouple the utility's profits from its sales using a revenue cap approach to setting electricity rates. (Synapse 1997) Removing utility financial incentives for energy efficiency programs is essential regardless of whether the utility is vertically-integrated or distribution-only. Because of this financial barrier faced by electric utilities, legislators and regulators should consider alternative entities for implementing energy efficiency programs.
- *Address barriers to distributed generation*. Electric utilities also face barriers to the development of distributed generation. As with energy efficiency, distributed generation on customers' premises can result in reduced T&D sales and thus reduced utility profits. In addition, many distribution utilities are prohibited from owning any form of generation, due to concerns about vertical market power. Regulators should identify policies to help overcome these barriers in order to allow distributed generation to play a meaningful role in portfolio management.
- *Provide appropriate cost recovery*. Some resource portfolios might not result in the absolute lowest-cost plan in the short-term, once other factors are considered. For example, hedging options may require higher up-front costs, but be desirable because of their risk benefits. Similarly, renewable resources might cost more than some fossil-fueled resources, but be desirable because of their diversity, risk, and environmental benefits. For example, coal-fired generation may appear cheaper in the short-run, but exposes the utility and its consumers to carbon dioxide mitigation costs in the future. Regulators need to provide utilities with some level of comfort that such additional expenses fall within the concept of portfolio management and can be recovered from ratepayers.
- *Pre-approval of resources and cost recovery*. The issue of cost recovery raises the question of whether regulators should "pre-approve" resource portfolios, and provide utilities with some certainty that they will be allowed to recover the costs associated with the resources therein. Pre-approval of resources with some assurance of cost recovery should be used with great caution, and only if certain critical conditions are met. It is essential that pre-approval only be applied to resource portfolios that were developed with proper portfolio management techniques, with meaningful and substantial input from key stakeholders, and with proper oversight from the regulators.
- *Pre-approval and resource implementation*. There is an important difference between pre-approval of a portfolio management plan, and pre-approval of the costs of specific resources acquired under that plan. Utilities must do more than plan well in order to be allowed to recover the costs of their resources. They should also be required to demonstrate on an ex post basis that they have

prudently and efficiently implemented the approved resource portfolio, and that they have properly responded to changing conditions since the plan was first developed.

- *Address market sensitive issues*. Regulators need to be aware that some of the information used in developing and assessing resource portfolios would be considered "market sensitive" by competitive actors in the electricity markets. As such, this information will need to be kept confidential to avoid market distortions or abuses. On the other hand, this issue should not be used to limit the information utilized and assessed in the portfolio management process. An efficient marketplace depends on a continuous flow of information, so that all buyers and sellers have access to the same data. Procedures can be established to ensure that market sensitive information is not provided except as part of a general system of disclosure equally applicable to all market stakeholders.
- *Facilitate the regulatory process*. Portfolio management involves many complex and challenging analyses and decisions, and regulators need to find a balance between (a) regulatory and stakeholder input and review, and (b) a feasible, timely process for developing, reviewing and approving resource portfolios. As described in Section 10.3, experience developed over the past decade in collaborative rulemaking and collaborative settlement processes for litigated cases should give some confidence that these complex matters can be addressed reasonably and expediently for the benefit of customers. In addition, commissions may avail themselves of the extensive case management tools developed in anti-trust and mass tort litigation, which go under the rubric of complex case management. (See, for example, Fed. R. Civ. P. 16(c)(12) and Federal Judicial Center 1995.)

References

Alexander, Barbara R. 2002. *Default Service for Retail Electric Competition: Can Residential and Low Income Customers Be Protected when the Experiment Goes Awry*?, Report to Oak Ridge National Laboratory Energy Division, April.

Alexander, Barbara R. 2003. *Managing Default Service to Provide Consumer Benefits in Restructured States: Avoiding Short-term Price Volatility*, June. Source: http://neaap.ncat.org/experts/defservintro.htm#MONTANA

Allayannis, G., and J. Weston 2001. *The Use of Foreign Currency Derivatives and Firm Market Value*, Review of Financial Studies, Vol. 14 pp. 243-276.

Keith, Geoff, Bruce Biewald, David White, Anna Sommer, and Cliff Chen 2003. *Cleaner Air, Fuel Diversity and High-Quality Jobs: Reviewing Selected Potential Benefits of an RPS in New York State*. Synapse Energy Economics, Inc. Prepared for the Renewable Energy Technology and Environment Coalition. July 28.

American Council for an Energy Efficient Economy (ACEEE) 2003. *Summary Table of Public Benefit Programs and Electric Utility Restructuring*, May, available at http://www.aceee.org/utility/index.htm.

Associated Press, 2003. "Nevada electricity rate increases among highest" September 1.

Awerbuch, Shimon 2000. "Getting It Right: The Real Cost Impacts of a Renewables Portfolio Standard," *Public Utilities Fortnightly*, February 15, 2000.

Bachrach, Devra, and Ryan Wiser, Mark Bolinger, and William Golove 2003. *Comparing the Risk Profiles of Renewable and Natural Gas Electricity Contracts: A Summary of the California Department of Water Resources Contracts*, Ernest Orlando Lawrence Berkeley National Laboratory, March.

Bernow, Stephen, Bruce Biewald, Jeffrey Hall, and Daljit Singh 1994. *Modeling Renewable Electric Resources: A Case Study of Wind*, Tellus Institute Study No. 91-187 for the U.S. Department of Energy. October.

Besser, Janet 2003. *The Future of Electricity Default Service: Lessons Learned*, Lexicon presentation for the NECPUC Annual Symposium, June.

Biewald, Bruce 2002. *Direct Testimony in Nevada PUC Docket No. 01-11029*, February 20.

Billington, Corey 2002. *HP Cuts Costs with Portfolio Approach*, Purchasing Magazine On-line, February, pgs. 1-4.

Bolinger, Mark, Ryan Wiser, and William Golove 2003. *Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation*, Ernest Orlando Lawrence Berkeley National Laboratory, August. LBNL-53587.

Boyer, Mike, 2003. "Cinergy to reduce airborne emissions: Voluntary effort aims at greenhouse gases." *Cincinnati Enquirer* September 10.

Brealey, Richard A., and Stewart C. Myers 2002. *Principles of Corporate Finance*, Irwin McGraw-Hill, New York.

Burlington Electric Department (BED) 2003. *The Climate Action Plan: A plan to save energy and reduce greenhouse gas emissions*. See: www.burlingtonelectric.com/SpecialTopics/Reportmain.htm

Burns, Robert E. , Kenneth Costello, Edwin Rosenberg, and Frank Darr 1999. *Market Analyses of Public Utilities: The Now and Future Role of State Commissions.* The National Regulatory Research Institute. NRRI 99-14. See: http://www.nrri.ohio-state.edu/programs/market/pdf/9914.pdf

California Legislature 2002. Assembly Bill No. 57, *Electrical Corporations: Procurement Plans*, September.

California Public Utilities Commission (CA PUC) 2002. *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*, Rulemaking 01-10-024, October 24.

CA PUC 2001. *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, October.

Cavanagh, R. 2001. "Revisiting 'the Genius of the Marketplace': Cures for the Western Electricity and Natural Gas Crisis," *The Electricity Journal*, 14(5) June.

Chicago Mercantile Exchange (CME) 2003. *Exchange Traded Derivatives in a Professionally Managed Portfolio*. Accessed Sept. 1, 2003, at http://www.cme.com/files/Exchange_Traded_Derivat.pdf

Cortese, Amy 2003. *From Green Knight to Utility King*, NY Times, July 6.

Costello, Kenneth, and John Cita 2001. *Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues*, The National Regulatory Research Institute, May.

Cowart, Richard 2001. *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, Regulatory Assistance Project (RAP) prepared for the National Association of Regulatory Utility Commissioners, June.

Coyne, James, and Prescott Harthorne 2003. *Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance*, Lexecon, Cambridge, MA, August.

Culp, Christopher L. 2001. *The Risk Management Process: Business Strategy and Tactics*, John Wiley, New York.

(US) Department of Energy (DOE) and EPRI 1997. *Renewable Energy Technology Characterizations.* TR-109496, December

Dixit, Avinash K., and Robert S. Pindyck. 1994. *Investment under Uncertainty*, Princeton U. P., Princeton, NJ.

Dutton, Christopher, 2002. *Green Mountain Power, Annual Meeting*, May 16, South Burlington, VT. http://www.gmpvt.com/pressrel/PR010205.htm.

Dyer, Jeffrey 1996. *How Chrysler Created an American Keiretsu*, Harvard Business Review.

Energy Information Administration (EIA) 1994. *Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities*. http://www.eia.doe.gov/cneaf/electricity/pub_summaries/finance.html

EIA 2003a. *Assumptions to the Annual Energy Outlook 2003*, Electricity Market Module, January.

EIA 2003b. *Status of State Electric Industry Restructuring Activity as of February 2003*, http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

EIA 2003c. Personal communication with Thomas Lee, July.

EIA 2002. *Derivatives and Risk Management in the Petroleum, Natural Gas, and Electricity Industries*, Energy Information Administration, October.

Engle, Gary 2002. Bond Laddering: A Gift for Income Investors. Ziegler Investment Services Group. See, http://www.ziegler.com/

Federal Judicial Center 1995. *Manual for Complex Litigation, Third*.

FEMP 2003. FEMP website: http://pnnl-utilityrestructuring.pnl.gov/energymanagement/states/texas.htm#stateefficiency.

Freund, Robert M., 2000. *Data, Models, and Decisions: The Fundamentals of Management Science,* South Western College Publishing, Ohio.

Gleason, James T. 2000. *Risk: the New Management Imperative in Finance.* Bloomberg, Princeton, NJ.

Green Mountain Power 2003. Green Mountain Power website: http://phx.corporate-ir.net/phoenix.zhtml?c=78917&p=IROL-profile.

Groppelli, A. A., and Ehsan Nikbaht 2000. *Finance*, 4th ed. Barrons.

Harrington, Cheryl et al. 2002. *Portfolio Management: Looking after Customers in a Market that Isn't Working Very Well*. The Energy Foundation, August.

Harrington, Cheryl, and Catherine Murray 2003. *Who Should Deliver Ratepayer-Funded Energy Efficiency? A Survey and Discussion Paper*, Regulatory Assistance Project (RAP), May.

Hollingworth, Kenneth 2003. Conversation with the Gillette Corporation's Purchasing Department, May 4.

Houston Lighting and Power Co. (HLPC), Corporate Planning Department 1988. *Resource Planning Using Decision Analysis*, photocopy, March 23.

Iman, R.L., and Helton, J.C. 1985. *A Comparison of Uncertainty and Sensitivity Analysis Techniques for Computer Models*, Technical Report SAND84-1461, Sandia National Laboratories, Albuquerque, NM.

Interlaboratory Working Group (IWG) 2000. *Scenarios for a Clean Energy Future*, Oak Ridge National Laboratory, Lawrence Berkeley National Laboratory, prepared for the Office of Energy Efficiency and Renewable Energy, US Department of Energy, November.

Interstate Renewable Energy Council (IREC) 2003. *Database of State Incentives for Renewable Energy (DSIRE)*. See: http://www.dsireusa.org/

ISO-New England (ISO-NE) 2003. *Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket*, ISO New England Inc. White Paper, p. 20, July 1.

Jaccard, Mark, and Rose Murphy, 2002. *BC's Electricity Options: Multi-Attribute Trade-Off and Risk Analysis of the Natural Gas Strategy for Vancouver Island*, Energy and Materials Research Group School of Resource and Environmental Management, Simon Fraser University, May 1, p. 11.

Kee, Edward D. 2001. *Vesting Contracts: A Tool for Electricity Market Transition*, The Electricity Journal, July p. 11-21.

Keith, Geoff, Bruce Biewald, David White, and Mike Drunsic. 2003. *Modeling Demand Response and Air Emissions in New England*, Synapse Energy Economics, prepared for the U.S. Environmental Protection Agency. September.

Krause, Florentin, and Joseph Eto 1988. *Least-Cost Utility Planning, a Handbook for Public Utilities Commissioners*, Volume 2, The Demand-Side: Conceptual and Methodological Issues, prepared for the National Association of Regulatory Utility Commissioners, Lawrence Berkeley Laboratories (LB), December.

Kushler, Martin, and Margaret Suozzo 1999. *Regulating Electric Distribution Utilities as if Energy Efficiency Mattered*, American Council for an Energy Efficient Economy (ACEEE), May.

Lazar, Jim, 1993. *Direct Testimony and Exhibits of Jim Lazar, Consulting Economist, On Behalf of Consumer Advocate. Before the Hawaii Public Utilities Commission; Docket No. 7310 - Avoided Cost.* February, 1993.

Levitan & Associates 2003. *Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket*, ISO New England Inc., July 1.

Maine Public Utilities Commission 2003. Maine Public Utilities Commission website: http://www.state.me.us/mpuc/orders/2002/2002-709odsop2.pdf, p.1

McKay, M.D., Conover, W.J., and Beckman, R.J. 1979. *A Comparison of Three Methods for Selecting Values of Input Variables in the Analysis of Output from a Computer Code*, Technometrics, pgs 221, 239-245.

Marcus, William B., and Greg Ruszovan 2000. *Mid-Atlantic States Cost Curve Analysis*. JBS Energy, Inc. Dec. 5.

Massachusetts Community Action Directors Association, Inc. (MASSCAP) 2001. *Comments in reference to: Competitive Market Issues,* Massachusetts Department of Telecommunications and Energy (DTE), June 14.

Massachusetts Department of Telecommunications and Energy (MA DTE) 2003. *Comparative Statistics from 2001 DSM Annual Reports*, July.

McNamara, Kristen, 2003. *Energy Industry Divided on Connecticut Contract Dispute*, Dow Jones Business News, June 11.

Moskowitz, David, et al. 2000. *Progress and Profits through Distributed Resources*, Regulatory Assistance Project, February

Nadel, Steven, Fred Gorden and Chris Neme 2000. *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*, American Council for an Energy Efficient Economy (ACEEE), November.

National Association of Regulatory Utility Commissioners (NARUC) 1988. *Least-Cost Utility Planning Handbook for Public Utilities Commissioners*, Volume 1, October.

Natural Resources Defense Council (NRDC) 2003. Personal communication with Sheryl Carter, San Francisco Office, August.

NEES 1993. *Option Theory Development*. Photocopy from NEESPLAN 94, June 1993.

Neustadt, Martha, 2003. *Intel Corp. Materials Department*. Conversation dated May 21.

Nevada Public Utilities Commission 2002. Order in Docket No. 01-11029.

Northwest Power Planning Council (NPPC) 2003. See: www.nwppc.org/energy/powersupply/adequacyforum/2003_0528/irprequirements.pdf.

Oppenheim, Jerrold 2003. *Testimony of Jerrold Oppenheim Regarding Electricity Standard Offer*, February 19, pg10.

PacifiCorp 2003. *Integrated Resource Plan*.

Platts Global Alert 2003. *Speculators Continue to Add to Long Positions in Crude Oil: CFTC*, Platts Global Alert, New York, July 7.

Platts Research and Consulting 2002. *Scenario Planning for an Uncertain World*, E News, No. 56, Nov/Dec 2002, 1-2.

Pye, Miriam, and Steven Nadel 1994. *Rate Impacts of DSM Programs: Looking Past the Rhetoric*, American Council for an Energy Efficient Economy (ACEEE), April.

Regulatory Assistance Project (RAP) 1996. *Making Room for Renewables*, Issue paper, July.

------ 2002. *Electrical Energy Security: Assessing Security Risks, Part I*. Issue paper, April.

Saintcross, John 2003. *Using Wind Power to Hedge Volatile Electricity Prices for Commercial and Industrial Customers in New York*, The New York State Energy Research and Development Authority, New York, May.

San Francisco Public Utilities Commission and San Francisco Department of Environment (SF) 2002. *Electricity Resource Plan*, revised ed. See: http://www.ci.sf.ca.us/sfenvironment/aboutus/energy/policy.htm

Sedano, Richard P. 1998. "Public Policy Goals and Challenges of Regional Market Transformation for Energy Efficiency." *Bench Marking Market & Changes Conference*. Northeast Energy Efficiency Partnerships. May 19, 1998, Windsor Locks , CT.

----- 2003. *Personal communication*, July.

Simchi-Leve, David, and Victor Martinez-de-Albeniz 2002. *A Portfolio Approach to Procurement Contracts*, Massachusetts Institutes of Technology: Operations Research Center, Dec. 1.

Synapse Energy Economics 1997. *Performance-Based Regulation in a Restructured Electricity Industry*, with Resource Insight, Peter Bradford and Jerrold Oppenheim, November.

Trebing, Harry M. 1998. *Concentration and the Sustainability of Market Power in Public Utility Industry,* Regulatory Assistance Project Issue paper, March

Trigeorgis, Lenos 1993. Real *Options and Interactions with Financial Flexibility*. Financial Management *22*, no 3: 202-224.

------ 1996. *Real Options: Managerial Flexibility and Strategy in Resource Allocation,*. MIT Press, Cambridge, MA.

------ and Scott P. Mason 1987. *Valuing Managerial Flexibility*, Midland Corporate Finance J. 17, no. 2/3, 16-28.

UBS Investment Research (UBS) 2003. *UBS sees near-term U.S. power price surge*, Reuters: Bulletin, July 8.

Vermont Department of Public Service (DPS) 1997. *The Power to Save: A Plan to Transform Vermont's Energy-Efficiency Markets.* http://www.state.vt.us/psd/ee/rstdsmpl.htm Accessed August 13, 2003.

----- 2003. *Distributed Utility Planning: An Introduction to Concepts and Issues*, http://www.state.vt.us/psd/ee/ee-DUP.htm Accessed August 8, 2003.

Wellman, Allen C. 2003. *Hog Cash Contracts Advantages and Disadvantages*, Nebraska Cooperative Extension NF 96-280, accessed via http://www.ianr.unl.edu/pubs/farmmgt/nf280.htm, June.

White, Gregory 2002. *A Mismanaged Palladium Stockpile Was Catalyst for Ford's Write-Off,* The Wall Street Journal Online, Feb. 6, pg 1.

Wonder Bread 2002. *Wonder Bread Annual Report*, 2002.

York, Dan, and Marty Kushler 2002. *State Scorecard on Utility and Public Benefits Energy Efficiency Programs: An Update*, American Council for an Energy Efficient Economy (ACEEE), December.

Yahoo 2003. http://bonds.yahoo.com/rates.html Accessed September 25.

Appendix A. Portfolio Management Details

A.1 Further Issues in Portfolio Management

The Academic Literature on PM

As explained in Chapter 4, a diverse portfolio is less risky than any single investment, and the same is true for commitments for commodity supply—such as electricity. Diversification works because prices of different investments are not perfectly correlated; historically a decline in the value of one investment is often offset by a rise in the price of the other. In any individual investment, there are two sources of risk. First is unique risk, which can potentially be eliminated by diversification. Unique risk results from events that are specific to an individual investment situation. In the context of the stock market, unique factors are those that affect a particular company or sector, such as a mistake or a disaster affecting the company's production or a broader disaster affecting supply of a particular commodity essential to the sector. Second is market risk. Market risks are those that are due to macroeconomic factors that threaten all investments equally. With respect to the stock market, these risks include changes in interest rates, exchange rates, real gross national product, inflation, and so on, which affect the price of stock for all companies or all sectors in roughly the same manner.[48]

Equity portfolio managers, for example at large equity mutual funds, maintain diversity by investing in a wide range of different companies in different industries. In these funds, portfolio diversity is measured by the percentage of investment in any one company, and the percentage of investment in any one industry, both of which are reported in fund profiles. While there are sector-specific funds, these are universally recognized as more risky than broad-market funds that eliminate unique industry risks through diversification.

While diversification of holdings is import to lessen the effect of both unique and market risks, having a portfolio with a diverse range of investment durations is equally important. Bond portfolio managers generally spread risk over a series of different maturities, while maintaining an average portfolio maturity that is reasonable. In fixed-income financial markets, this is achieved by setting up a bond ladder, a series of bonds with a range of maturity dates. The advantage of this method is that the investor reduces the impact of volatile interest rates on the portfolio. If rates rise, the investor will soon have bonds maturing with which he/she can reinvest at the higher rates. Similarly, when rates decline, one can take comfort knowing that a good portion of the portfolio is locked-in at relatively high rates. These same concepts that apply to volatility in interest rates apply to commodity spot markets. If prices are falling, one will soon be able to begin

[48] Diversifying into different uncorrelated or counter-cyclical markets, in turn, can mitigate market risks. For example, allocating some investment to cash, bonds, or commodities can to some extent diversify equity market risk. See, for example, Culp, 2001.

taking advantage of that, while if they are rising, one is only gradually exposed to the full impact of that rise in price.

There is an entire class of mutual funds known as "balanced" funds. These are funds that invest in both equities and fixed-income instruments. Their equity investments are diversified across many industries, and their bond investments are diversified over many different maturities. Fund managers consider the risk of each asset and the overall portfolio. There are some managers that invest only in low-risk securities (i.e., companies with an expectation of stable earnings) while others are characterized by higher risk profiles, seeking to achieve higher returns.

The take- home message from the financial markets is that diversification reduces risk or volatility in prices. The unique part of the uncertainty in any individual investment is diversified away when that investment is grouped with others into a portfolio of different investment types and durations. Overall, diversification gives the investor more flexibility and protection from unknowns.

Portfolio Management: The Theory as Applied to Commodities

Just as diversification can protect investors from uncertainties in financial markets, diversified management approaches can protect companies and market participants from unknown changes in their industries. To decrease the impact of unique risk factors, a diversified portfolio for a utility might contain a mix of generation assets with uncorrelated prices and supplies. The well-managed portfolio will also draw from both demand- and supply-side resources and efficiency improvements, as well as a mix of short-term, medium-term, and long-term contracts to ensure price protection over time. In addition, if there is owned generation in the portfolio, risk protection will be further enhanced by applying the same portfolio management approaches to fuel acquisition, a technique long practiced in that part of the utility industry.

Varieties of Procurement Contracts and their Pros and Cons

Portfolio management in terms of commodities purchasing agreements between buyers and suppliers is at the forefront of current research at institutions such as MIT's Center for E-business. A well-managed contract portfolio is usually a combination of many traditional procurement contracts, such as long-term contracts, options and flexibility contracts, and usage of spot markets. Each of these elements has its own pluses and minuses, but in combination they can greatly reduce risk.

- Use of the spot market involves paying market price on the day that the commodity is needed. Spot market pricing can be quite volatile, and thus represents a risk for buyers. On the upside, buyers do not need to make any commitments, since spot market buying requires no advance agreements. Spot market reliance can be considered as protection against both falling demand and falling prices.
- Long-term or forward contracts are agreements between buyers and suppliers to trade a specific amount of a commodity at a pre-agreed upon price over time. No money actually exchanges hands until the commodity delivery date. The

advantage to these contracts is that the buyer is no longer exposed to spot market volatility. However, he/she risks signing an agreement when the spot market is high relative to future prices. All forward contract details are the responsibility of the individual buyer and seller. A strategy of purchasing forward contracts can be considered as a protection against drying up of supplies and rising prices.

- In an option contract, the buyer prepays a small fee up front in return for a commitment from the supplier to reserve a certain capacity on a good for future potential trade at a pre-negotiated price called the "strike price." In this case, total price is higher than the unit price (offered at *that time*) in a long-term contract, but one does not need to commit to buying a specific quantity. Typically, the buyer exercises the options only when spot prices exceed the agreed upon strike price of the option. If market prices are less than the strike price, the option fee has already been paid and may be thought of as the sunk cost of an insurance premium.
- A flexibility contract, on the other hand, exists when a fixed amount of supply is determined when the contract is signed, but the amount to be delivered and paid for can differ by no more than a given percentage determined upon signing the contract. Flexibility contracts are equivalent to a combination of a long-term contract plus an option contract. (Simchi-Leve 2002)

With regard to the different kinds of contract agreements, the buyer needs to find the optimal trade-off between price and flexibility. In other words, the buyers needs to find the appropriate mix of low price, yet low flexibility (long-term contracts,) reasonable price but better flexibility (option contracts) or unknown price and supply but no commitment (the spot market.) In addition, purchases should vary in duration, the way a bond portfolio might be laddered.

Derivative Instruments

So far, this subsection has focused on the actual contracts signed between buyers and sellers of commodity items. However, in addition to the work of managing a portfolio of contracts to support physical supply chain operations and logistics, many corporations have entire groups within their finance departments devoted to financially hedging or offsetting the pricing risk of key commodities through the use of derivatives. Financial derivatives have definite advantages over forward, fixed-price contracts. Most important, in many markets they are more liquid and have lower transaction costs.[49]

[49] It is important to keep in mind that there are distinctive requirements that apply to accounting for derivatives under the tax code and under financial accounting standards. As has been evident to anyone following the business news in the past few years, these requirements can have critical impacts on the financial results of a corporation and must be carefully evaluated and understood to avoid difficulties. A few scandals aside, these requirements do not impair the beneficial aspects of derivative use, but rather ensure that investors, managers and regulators are properly informed. In fact, there are related requirements that apply to financial reporting of commodity contracts, as well. Expert professional advice in these areas is recommended prior to establishing a financial derivatives program.

Derivative theory can be complex, but the core concepts are straightforward. In simplest terms, the worth of a derivative is based on the value of an underlying commodity or asset. One can think of derivatives as side bets on the value of the underlying asset. Like insurance, use of such "hedges" reduces the effect of unknown events in return for a fee. The most common derivatives are futures contracts and swaps.

- *Futures contracts* are advance orders to buy or sell an asset. Like long-term, forward contracts, the price is fixed today, but the final payment does not occur until the delivery day. Unlike forward contracts, futures contracts are highly standardized and are traded in huge volumes on the futures exchanges. Those investing in futures contracts do not necessarily have any direct connection to or use for the commodity being traded. Instead, investors take part in the futures market in efforts to either profit from or protect their financial portfolio from the ups and downs in the price of one or more of the dozens of different commodities, securities, and currencies that are traded. If a buyer does not close out his/her position (sell the purchase contract to another buyer) before the delivery date specified by the futures contract, he/she must take physical delivery of the goods or sell them at the market price prevailing on the closing date.[50] However, futures contracts are rarely held to maturity, except, perhaps, by physical suppliers and consumers of commodities. They are readily traded, as profits and losses from these derivative instruments are realized daily. Generally, full service brokerage firms are used to handle investments in futures contracts. Specialist brokers, such as NatSource, trade electricity futures in some markets. Fees are paid to the futures commission merchant, the clearing corporation, the National Futures Association (NFA) and the futures exchange on which the contract trades. Taken together, these fees can range anywhere from $25 per contract for discount brokers who offer very little if any customer services, to over $95 per contract for full-service brokers. Additional services provided by full-service brokers consist of market commentaries, identification of trading opportunities, and trading tips or advice.
- A *swap* is a contract that guarantees a fixed price for a commodity over a predetermined period of time. At the end of each month, the prevailing market settlement price of the commodity is compared to the swap price. If the settlement price is greater than the swap price, the supplier pays the buyer the difference between the settlement price and the swap price. Similarly, if the settlement price is less than the swap price, the buyer pays the supplier the difference. Swaps were created in part to give price certainty at a cost that is lower than the cost of options. In swaps, no physical commodity is actually transferred between the buyer and seller. The contracts are entered into outside of any centralized trading facility or exchanges, making them over-the-counter

[50] Conversely, if a seller does not cover the contract with a purchase from another seller by the closing date and cannot physically deliver, the seller must pay the market price prevailing on the closing date to make good on the promised sale. In most markets, the brokers or market makers perform these functions automatically and present bills to investors who are not physical suppliers or purchasers.

(OTC) derivatives. Payment is sometimes direct, though often times through an intermediary bank or counter-party.

Financial companies are constantly coming up with new types of derivatives and variations on currently used instruments in order to suit a range of investor interests. These include weather derivatives, and a form of swap known as a contract-for-difference.

Derivatives should be viewed as financial insurance instruments that protect the buyer from spikes (and the seller from dips) in commodity pricing. The intent of such hedging is to stabilize prices, not to lower them. In fact, risk adverse investors who seek protection from price volatility should be willing to pay an insurance premium. This premium might come in the form of transaction cost, or the difference in price between the bid and offer prices, known as the spread. In liquid markets, transaction costs (i.e., bid/offer spreads) are typically very small, and of little concern. In less-liquid markets, however, bid/offer spreads can be wide, and can have a more significant impact on the cost of transactions.

While derivatives do have their place in commodities risk management, they also have been the objects of scrutiny in a myriad of cases in the last 10 years. For example, in 1993, Orange County lost $1.7 Billion due to financial derivatives use. Meanwhile, Enron's 2001 bankruptcy, while not caused by derivative use, raised concerns about risk management and transparency of financial information. (EIA 2002)

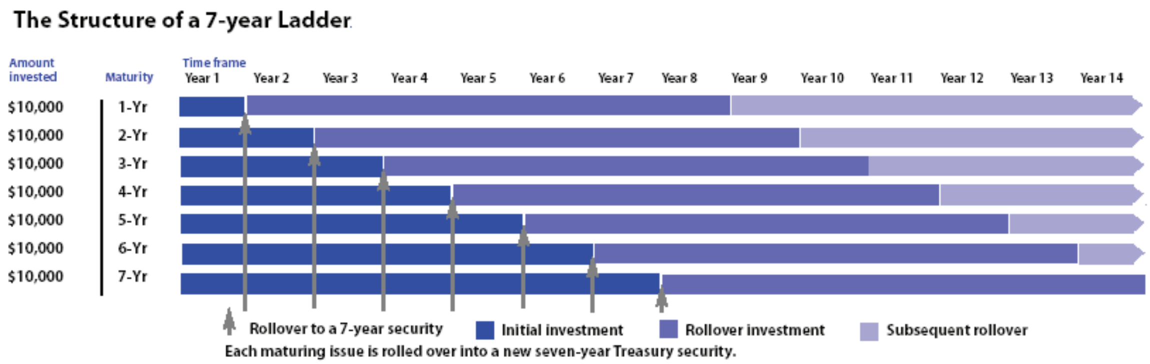
Price Averaging

Another well-accepted technique that can help manage the risk of a portfolio is called dollar-cost averaging. To dollar-cost average, a buyer will make several investments of equivalent dollar value in equally spaced time increments, regardless of price. For example, instead of agreeing to an annual commodities contract settlement of $50 million on Jan. 1, a buyer may instead agree to purchase $5 million worth of goods every 36.5 days. While some of the contract prices will be higher or lower, based on the spot price on the given day of settlement, the math for this technique guarantees that the buyer will acquire more goods when they are inexpensive and less when they are costly. This technique promises buyers that they do not have to worry about spot market prices on any given day. However, when using this method, instead of price fluctuations, buyers do experience fluctuations in volumes of goods purchased. As long as the buyer can bear these changes in volumes, dollar cost averaging is an excellent technique to manage price fluctuation risk.

Bond Laddering

Bond laddering is an investment strategy where the portfolio manager invests monies in bonds with a range of maturity dates. For the purposes of this example, we will choose a bond laddering range of 7 years, a beginning balance of $70,000 to be managed, and US treasuries as our financial instrument. Using this strategy, on day one, the portfolio manager divides up the monies into $10,000 portions and buys 7 Treasuries with durations of 1, 2, 3, 4, 5, 6, and 7 years respectively. As each bond matures, the portfolio manger reinvests the proceeds in Treasuries that will mature seven years from that date and, in effect, continues to build the ladder into perpetuity, as illustrated in Fig. A-1, below. (Engle 2002)

Figure A-1. Bond Laddering Example



There are several benefits from adopting this strategy. First, laddering reduces risks associated with market timing. Instead of trying to predict the best time at which one should lock in an interest rate, laddering provides both a range of current interest returns (capturing variation in the current term structure of interest rates) and, more importantly, a range of future investment opportunity time frames. Laddering also achieves immediate positive returns regardless of current economic conditions, unlike simply hiding the money under the mattress until economic conditions improve.

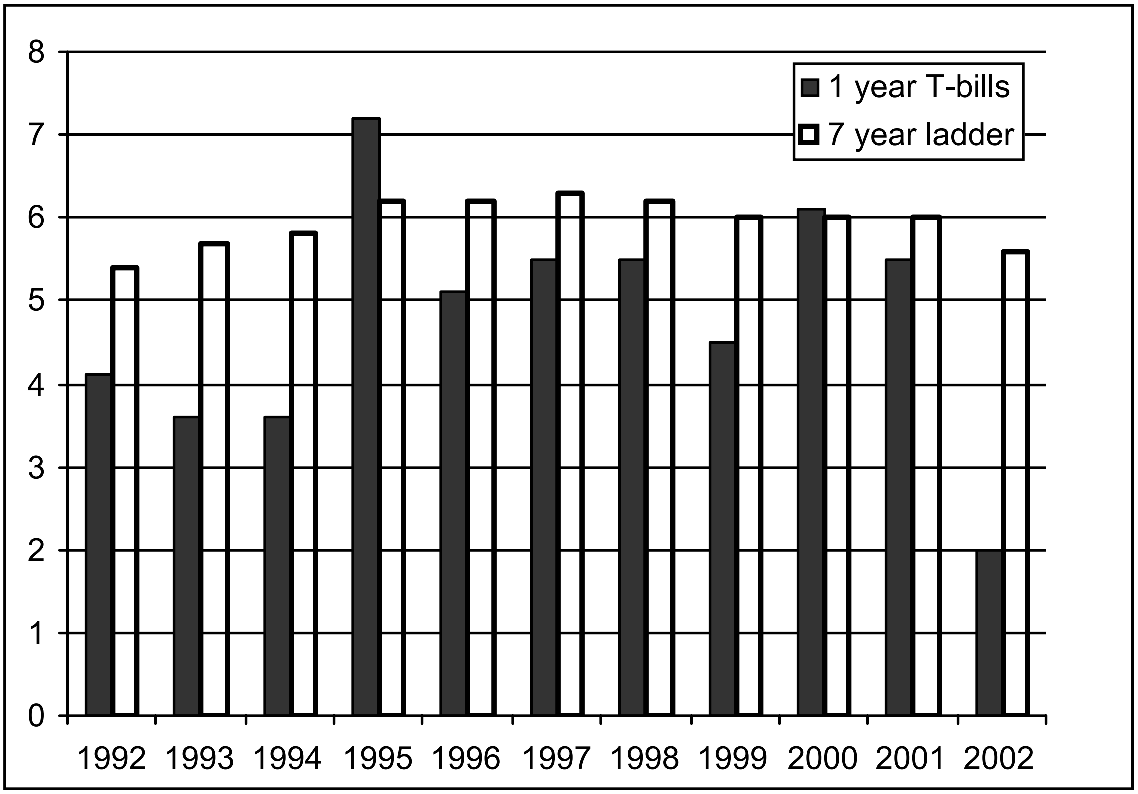
The second major benefit of a bond laddering strategy is that it provides some of the benefits of a longer-term investment, while retaining some of the benefits of a short-term investment strategy. In other words, in the laddering strategy, an investor commits funds neither to just the short-term nor just the long-term. Because a portion of the portfolio expires each year, laddering simulates a short-term liquidity risk approach. However, because funds are invested in a range of durations--averaging 3.5 years for the initial investments and increasing to 7 years over time--the returns on the portfolio are similar to those of longer-term investments, which typically yield higher returns, as described below, while avoiding the risk of locking all of the assets into a single long term investment at what may turn out to have been a time when the yield was lower than average.

Table A-1. Term Structure of US Treasury Yields September 25, 2003.

Maturity	Yield (%)
3 Month	0.83
6 Month	0.95
2 Year	1.62
3 Year	2.04
5 Year	3.01
10 Year	4.09
20 Year	5.00

In Table A-1, we see US treasury yields as of September 25, 2003. (Yahoo 2003) The data represents the available yields for bonds with various durations. Usually, the longer one commits monies to a particular investment fixed interest rate instrument, the greater the yield that is available. Thus, the fact the bond ladder returns rates of an average 3.5-7 year duration, while freeing up 1/7th of the portfolio yearly, is far better than simply investing in 1 year treasuries alone. This is illustrated in Fig. A-2. Here, we see that, over the10 year period from 1992-2002, 1-year treasuries returned 4.8% on average, while a 7-year ladder returned 5.9% annually on average over the same time period.

Figure A-2. Yearly Returns on the Bond Ladder Relative to Treasury Bills



So, investing in a laddered approach is superior to investing in 1-year treasuries, in terms of returns. However, one might ask, what would happen if one were to invest one's funds all at once into a 10-year treasury instead of annually into 1-year treasuries? According to our chart, 10-year treasuries currently yield 4.09%, which is lower than both the historical return on 1-year treasuries and on our ladder. Now, of course, 10-year yields in the past have oscillated, sometimes yielding higher than our laddered strategy and sometimes yielding lower returns. But again, the laddered approach eliminates both the risk that one will choose a "bad" time to lock in a rate for one's entire portfolio and the risk of having to reinvest all of that portfolio in a less than ideal economic environment upon maturity of the bond.

In short, a laddered investment strategy is both simple to set up and to manage. Through diversification, this strategy both reduces volatility of returns and drives up average returns.

Allocation of Risk between Buyers and Sellers

Turning to financial hedging instruments, derivatives allow buyers to transfer risk to others who could profit from taking the risk. Those taking the risk are called speculators. Speculation is an activity where the parties take on more risk with the expectation of earning a profit. Speculators seek price volatility, while hedgers or buyers in our case are more interested in obtaining fixed prices. Speculators play a critical role in derivative markets, as they are willing to assume the risk that the hedger seeks to shed. Some speculators, like insurance companies or brokerage firms, have some advantages in bearing risk. First, due to experience, they may be good at estimating the probability of events and price risks. Second, they may be in a position to provide advice to buyers on how to reduce risk and thus lower their own risks. Third, they can pool risks by holding large, diversified portfolios of agreements, most of which may never seek payments.[51]

It is generally understood that there is a fine line between hedging to mitigate volatility and hedging for the purpose of pure speculation to earn profits. Imprudent speculation is undoubtedly an issue of concern for any industry's participants. It is up to regulators to better define this line.

> Futures contracts are held not only by market participants, but also by industry outsiders, including speculators. For example, as of July 1, 2003, large hedge funds, whose owners are non-participants in the oil market, were holding 51,546 contracts in long positions in the crude oil futures and options markets. Meanwhile, small speculators were holding a net long position of 19,207 contracts. As for oil companies, refiners and banks, 41,999 net short contracts were being held, split almost evenly between the futures and options markets. (Platts Global Alert 2003)

At this point, one might ask why a supplier would be willing to negotiate several types of contracts, instead of insisting on long-term contracts only; in a long-term contract, the buyer is obligated to purchase the commodity whether or not it is needed and therefore the buyer bears all of the risk. To begin with, it has actually been demonstrated that a portfolio of an option and a long-term contract is a win-win situation for both the buyer and the supplier instead of a zero-sum game. This is true simply due to the fact that suppliers usually face multiple buyers. Suppliers are actually better able to handle demand uncertainly when they pool the various risks of several buyers together, rather than dealing with demand uncertainty of a single buyer only. (Simchi-Leve 2002) Also, while it is true that long-term contracts provide the supplier with guaranteed revenue streams, they often result in smaller numbers of orders/buyers due to lack of flexibility. Thus, option contracts can be attractive for building buyer relationships and reducing risk. In addition, in option contracts, suppliers generally earn a higher margin, as they can charge more for an option than they can for a guaranteed agreement. Thus, a mix of contracts seems to be a win-win situation in reducing risks for both the buyer and the supplier.

[51] Risk pooling among default providers may be promising, but needs to be further developed as a concept for application in the electricity industry.

The Build-Versus-Buy Decision

The previous discussion focused on the benefits of and tools for assembling a portfolio of various types of purchase contracts and derivatives to manage portfolio risk - primarily the portfolio risk faced by the buyer in a wholesale commodity market. But an entity, such as a default service utility, has a whole additional class of supply-side options--generating plant construction and ownership.[52] Under traditional rate regulation, ownership of generation was often the norm; primary reliance on purchases was mainly a strategy used by municipal and cooperative utilities, although many of them also owned plants or shares in plants.

Ownership of production facilities is, in some ways, analogous to buying the ultimate forward contract. Ownership brings with it complete insulation from spot price fluctuations and market power of suppliers. Unfortunately, plant ownership brings with it a large degree of unique risk, which must then be borne or mitigated. Some of these risks, well known from traditional regulation, are forced outages from equipment failures or other causes, labor actions, construction delays and overruns, fuel price and supply interruption risk, environmental risks, and natural disasters. Naturally, like any long contract, plant ownership as part of the portfolio meeting one’s needs can create problems if demand drops significantly. Plant ownership may also prevent a utility from taking advantage of downward fluctuations in market prices. Ownership also requires large commitments of capital and management resources.

Important variables to consider in such a decision include the plants’ fixed costs and capital requirements, fuel and other variable costs, emissions, and lead time, which vary considerably as seen in Table 7.1, above. If physical, or resource-based, contracts are being considered, the type and length of contracts, quantity determination, provisions for ancillary services, and selection among providers are all relevant. In either case, or if a combination of these approaches is contemplated, appropriate hedging strategies and management of trading and plant operation functions need careful consideration.

Both physical plant ownership and resource-based contracts bring with them advantages and disadvantages for PM. For example, long term rights to energy that is not tied to the prices or environmental risks of fossil fuels, resource-based contracts are potentially attractive. In many markets, long-term, fixed-price contracts are available *only* through resource-based contracts with owners of specific renewable plants or groups of plants. Indeed, many renewable energy projects must rely on such contracts if they are to be bankable at all. Such projects are also often highly modular, physically, allowing such resource-based generation assets to be laddered and diversified.

On the plus side, ownership enables the buyer to acquire specific types of resources with characteristics not available from the competitive market. For instance, a manufacturer may wish to build certain components to ensure they meet needed quality standards. As

[52] In addition, a utility can own the underlying fuel supply resource, by acquiring gas resources in the ground, coal-bearing property, or other “ownership” of fuel resources. This is not examined in this paper, but we note that this practice has been highly controversial in the past (captive coal), but also offers opportunities for reducing power cost volatility in a utility resource portfolio.

another example, there has been little development of renewable energy sources in many wholesale electricity markets, despite their environmental and long term risk benefits. If default service providers, their customers, or their regulators were to value such advantages, one way to obtain them, like any long term forward asset acquisition, would be to build and own the generating assets directly.

A plant owner also becomes a potential supplier in whatever wholesale markets exist for the product. Excess output can be marketed, perhaps at a profit. Some portion of the capacity can be used to sell options or other products to mitigate the mirror image risks that suppliers face.

A specific set of risks associated with forward contracts in a competitive wholesale marketplace has to do with the market power physical suppliers can exert. If the supplier owns the assets, the parties are considered nonintegrated. If the buyer owns the asset, the parties are integrated. The primary point here is that under non-integration, the supplier can use or threaten to use the asset in the market in a way that is not optimal for the buyer. For example, the supplier can simply withhold supply from the market. This concept is known as hold-up, as the supplier can hold-up or stop critical supplies from reaching the buyer until the market price has risen.

We normally expect competitive wholesale markets to provide suppliers with strong incentives to build value into their assets in order to improve their bargaining position with all parties. In a properly functioning market, the non-integrated supplier may invest great time and effort into improving efficiencies and offering best in class products and services. In contrast, under integration, there is no hold-up threat, because the buyer owns and hence controls the asset. In this setting, there is nothing to bargain about: the buyer owns the good and so simply takes it. The supplier loses control over the decision to sell to other buyers (and the decision to sell at all.) The supplier's only operational incentives come from the buyer, and thus, unless these incentives are heavily monitored and controlled, the supplier has no incentive to incorporate efficiencies or improve operations. Thus, while hold-up exists under non-integration, efficiencies, incentives, and operations may be better for both the buyer and supplier under non-integration than under the integrated scenario.

The preceding paragraphs encapsulate one policy argument for divestiture of power supply when competitive wholesale markets are created. The fact that those forces are not fully effective means that plant ownership may remain a useful option. Among the reasons these forces are not fully effective is a different perception by financial markets among the risk, and therefore the cost of capital, for merchant power plant owners compared with utilities serving retail customer loads. This differential is presently very significant. In addition, financial markets continue to assign a portion of the risk associated with long-term power costs to the purchasing utility, and this affects the buy versus build decision. These issues are significant, and will be discussed in Chapter 7.

In sum, because of its potential benefits to consumers, default service providers should evaluate plant construction and ownership as a possible component to their portfolio. However, ownership clearly adds additional and different risks that must also be managed appropriately. In many retail choice jurisdictions, the transition to competition has resulted in institutional constraints or strong disincentives for plant ownership.[53] Regulators (or legislators) may wish to evaluate and consider revising those systemic limitations.

A Buy vs. Build Example

It is informative to look at an example of the economics of the build versus buy decision for an electric utility. In the following analysis, we look at the cost of electricity from a natural gas combined-cycle plant under two different financing scenarios:

- A generating plant constructed and owned by a regulated utility.
- A generating plant constructed and owned by an independent power producer (merchant plant) with a long-term contract.

The analysis identifies the costs of capital for each situation based on the costs of raising equity versus debt financing under the different capital structures. We then estimated the levelized costs of electricity generation (in $/MWh), in order to compare the effects of the different financing scenarios. Results are shown in Table A-2. The documentation and assumptions for this analysis are provided below.

Table A-2. Levelized Price for Electricity Under Different Financing Scenarios

	Percent Debt Financing	Percent Equity Financing	Cost of Debt (%)	Cost of Equity (%)	Capital Recovery Period	Capital Recovery Factor	Levelized Price ($/kWh)
Regulated Utility	50%	50%	8	11	30 yrs	10.3%	44.5
Merchant Plant	80%	20%	12	16	20 yrs	13.6%	48.4

This analysis indicates that, all other things being equal, it is most economical for a regulated utility to build and operate its own generating facility. This is true because a regulated utility is, in general, the least risky of the three options and, thus, has lower costs of both equity and debt compared with a merchant plant.

The cost of power from the merchant plant is higher than the utility for two reasons. First, the merchant plant has a higher cost of debt and equity because they are a greater risk to their investors. Second, merchant plant owners typically need to recover their costs over a shorter time period than regulated utilities, because of the greater risks and because power contracts tend to cover shorted periods than the book life of the regulated power plant. This shorter capital recovery period is responsible for the largest portion of the difference between the regulated utility and the merchant plant. Of course, an electric utility would also need to consider all the costs and benefits of these different options, including the risks associated with owning a plant or entering into a long-term forward contract.

[53] This is not to say that vertical market power was not an issue that needed to be addressed at the time that divestitures were required.

One benefit of plant ownership is that if the resource has value at the end of the original estimated project life, the utility "owns" it and the remaining life is available to serve consumers without having to pay a second time for the same resource. There are many power plants, primarily coal and hydro, that have long outlived their original estimated operating lifetimes and original financing assumptions. If the utility is purchasing a power contract, it receives protection in the event that a resource fails before the end of the contract, but gives up the potential for economical plant life extension unless this is provided for in the original contract. Some contracts do provide the utility with the right to purchase the resource for a specified price at the end of the contract, thus preserving this potential value.

Assumptions for Buy vs. Build Example

Financial Assumptions:

Most of the financial assumptions were based on those used by the US Energy Information Administration in preparing the Annual Energy Outlook (EIA 2003c)

- *Economic Life* – A capital recovery period of 30 years was assumed for the power plant owned by regulated utility. This is based on the typical depreciation schedule for a power plant owned and operated by electric utilities. An economic life of 20 years was assumed for a merchant plant. This is based on our estimate of the typical period that investors require to recover the capital costs of merchant plants. In practice, this economic life might be higher or lower, depending upon the financial circumstances of the power plant owner.
- *Financing Structure* – For the regulated utility, we assumed a 50% equity, 50% debt financing structure. This was based on a conversation with EIA, wherein we were told that the 2002 assumptions were 45% equity and 55% debt for new utility projects. Yet, there was strong belief that future financing values for 2003 and the foreseeable future would have less debt and thus we lowered the values to a 50/50 split. For the merchant plant with a contract, we assumed a 20% equity, 80% debt capital structure.
- *Debt Term and Cost* – We assumed the debt term to be a period of 30 years for the regulated utility, and 20 years for the merchant plant with a contract. For the regulated utility with a 50/50 debt/equity structure, we assumed debt costs to currently be in the range of 8%. For the merchant plant with higher debt financing, we assumed debt costs to currently be in the range of 12%.
- *Equity Cost* – Based on conversations with EIA, we assumed equity costs of 16% for the merchant plant. For the regulated utility, we assumed equity costs to currently be in the range of 11%.
- *Tax Depreciation* – We assumed an accelerated tax depreciation schedule over a 20 year tax life for both the regulated utility and the merchant plant.
- *Other taxes* – We assumed a federal tax rate of 34% based on EIA assumptions and an 8.8% average state tax rate.

- *Inflation rate* – We assumed inflation to currently be in the range of 2.5%.
- *Property Tax* - Property tax as a percent of the investment cost. This can vary substantially by location, but 2% ($20 per $1000 of valuation) is typical. The payment is considered to be constant in real dollars over the operating life of the plant.

Power Plant Cost and Operating Assumptions:

Unless otherwise noted, the power plant cost assumptions were based on those used by the US Energy Information Administration in preparing the Annual Energy Outlook (EIA 2003a) The assumptions below are for a conventional natural gas combined cycle unit. All costs are in 2001 dollars.

- *Capital Costs* – Overnight capital costs for a plant constructed in 2001, including contingencies: $536/kW. All-in construction cost, including interest during a three-year construction period: $620/kW.
- *Fixed O&M* – $12.26/kW-yr.
- *Variable O&M* – $2.0/MWh.
- *Heat Rate* – 7,000 Btu/kWh**.**
- *Fuel Price* – $4/MMBtu. Assumed to represent the levelized fuel cost over the twenty-year study period, in real terms.
- *Capacity Factor* – 60%. Assumed to represent a mid-merit power plant in a competitive wholesale market.
- *Emission Allowance Costs* – none. Natural gas combined-cycle units emit very small amounts of SO_2. For simplicity, we assume that the unit is located in an area with no cap on NO_X allowances.

Conclusion

Across many industries and over long periods of time, the optimal approach to portfolio management is generally found to be a balance of contracts of varying durations, price terms, and raw materials, and some small reliance on spot market, possibly supplemented with hedging instruments. In addition, long-term contracts or plant ownership can be "economically efficient" and make good sense in some situations.

A.2 Portfolio Management in Non-Electricity Industries

Companies in all industries are concerned about market risks. For product companies, these risks take the follow forms:

- Inventory risk due to uncertain demand by customers
- Rate change risks due to uncertain changes in international rate of exchanges

- Commodities risk due to uncertain cost of raw materials and resulting changes in the spot market

Companies are taking great strides to mitigate such risks, as over 60% of a typical producer's revenue is spent on raw material costs and services. For inventory risk, companies are favoring just-in-time manufacturing, wherein the company works closely with a supplier to ensure that inventories are kept at a minimum, but that there is constantly enough supply to match customer demand. For currency rate change risks, companies have begun to invest in financial swaps and derivatives, which allow companies to lower risk when selling/buying goods within international markets.

In the discussions below we focus on the third kind of risk, commodities risk, because this is the most important type of risk to electric utilities. We begin with a discussion here of how non-electricity companies attempt to mitigate these risks, and then describe recent efforts by electricity utilities.

Traditional Supplier Contracts

Traditionally, manufacturing companies have signed forward contracts with suppliers of critical commodities. The decision to use a traditional forward contract revolves around the current and expected future directions of market prices, the volatility of the market, and how soon a market direction change is expected. For both buyers and sellers, forward contracts guarantee the transaction of a known quantity and price of goods for a given time frame. From the buyer's perspective, the contract not only guarantees delivery of a critical good, at an agreed upon price, but also reduces the costs of procurement operations, as prices can be negotiated less frequently.

The typical length of a contract is dependent on the lifecycle of the industry or product. In the pork industry, type and quality of product might be considered constant and demand can be well forecasted. Hog cash contracts are typically renegotiated every 3-7 years. (Wellman 2003) Similarly, Gillette manufacturing, which has a long-term forecasted demand for steel for its razor blades, enters one-year contracts, typically with at least two suppliers worldwide. (Hollingworth 2003) Having multiple suppliers ensures competitive pricing from suppliers and mitigates the risk that one might not be able to meet demand. It also allows the staggering of contract start dates, such that the company is less affected by a price swing at the beginning of its buying cycle.[54] At companies with faster life cycle products, such as Intel, contracts are negotiated anywhere from every quarter to every several years. For instance, with regard to CPU processors, with a lifetime of only a few years, multi-year contracts are typically avoided, as CPU obsolescence limits the contract horizon. (Neustadt 2003) Overall, studies show that the average commodity is re-priced roughly once a year.

---

[54] This does not seem to be common practice at either Gillette or at other consumer goods companies.

Commodity Procurement at Ford Motor Co.

While there are many advantages to long-term contracts, there are also disadvantages, particularly if they are not hedged or staggered and split among competing suppliers. In the early 1990's, most of Ford Motor Company's catalytic converters relied heavily on palladium metal. Global auto-industry demand for palladium had nearly quintupled between 1992 and 1996. Accordingly, prices slowly began to rise. However, because Russia had historically made its palladium available to American consumers, Ford figured the market would continue to remain roughly in balance despite the increases in demand. But, in 1997, Russia shocked the market by holding up palladium shipments to the US, resulting in a 3-fold increase in the price of palladium. Supply and demand oscillated for the next several years. Finally, in 2000, Ford's top managers approved a proposal to begin lining up long-term contracts and begin stockpiling palladium, despite the fact that prices were at record highs. Stockpiling was an unusual practice at Ford, and the Company did not have a process in place to use options to hedge the risk of changes to rare commodities prices. Yet, Ford went ahead and signed the long-term contracts for palladium shipments.

In the summer of 2001, there was yet another price shock in the palladium market. This time prices fell sharply to $350/ounce, a 60% drop from their January $1000/ounce highs. Yet, by this time, Ford had already engaged in the long-term contracts with suppliers and their inventory was immense. In 2002, the Company was forced to make a $1 Billion write-off due to the difference between the market and book value of its palladium stockpiles.

Thus, while Ford had locked in a known price for palladium, the price fluctuation had resulted in overpayment and overstock of this rare commodity. Ford's mistake put the company in a very difficult situation in terms of answering to its investors' questions regarding the company's ability to manage commodity price risk. (White 2002)

Derivative Use in Other Industries

Aside from engaging in longer-term contracts and relational contracts, most leading chemical, agricultural, and consumer goods corporations use commodity swaps and commodity derivatives as tools to limit market risk. For instance, at Wonder Bread, market risk is discussed in the annual report:

> Commodities we use in the production of our products are subject to wide price fluctuations, depending upon factors such as weather, crop production, worldwide market supply and demand and government regulation. To reduce the risk associated with commodity price fluctuations, primarily for wheat, corn, sugar, soybean oil and certain fuels, we enter into forward purchase contracts and commodity futures and options in order to fix commodity prices for future periods. A sensitivity analysis was prepared and, based upon our commodity-related derivatives position as of June 1, 2002, an assumed 10% adverse change in commodity prices would not have a material effect on our fair values, future earnings or cash flows. (Wonder Bread Annual Report, 2002)

In other words, thanks to Wonder Bread financial managers, investors can be assured that a 10% swing in spot market prices for their raw material commodities will have an insignificant effect on the company's net income. Better yet, studies have shown that those companies that have begun to use financial hedging have seen an overall increase in their market value, whereas those that have abandoned hedging for some reason have shown a statistically significant decrease in market value. (Allayannis 2001)

A.3 Special Topic: Instruments for Use in the Transition Period Prior to Deregulation

The introduction of competitive markets is often accomplished by breaking up vertically integrated companies. For electricity, this means de-integration of large utilities that not only generate electricity, but also own transmission lines, and possess long-term power purchase agreements. Thus, industry restructuring means changes to the ownership and management of traditional industry infrastructure, which in turn affects spot market prices. Vesting contracts, as defined, are hedge contracts that are put in place prior to the divestiture of generation assets. Their main features are that they are regulated contracts that are not freely negotiated in the marketplace. Instead, vesting contracts are useful in the transition period from a regulated market to a more mature electricity market. These contracts allow the de-integrated industry segments to function without exposing them to abrupt changes in risk. They protect customers from spot market prices, promote the hedge contract market, and provide incentives for competitive entry. Companies can enter the deregulated environment with portfolios made up of only vesting contracts. As these contracts expire, parties can renegotiate and move to a mix of vesting and market-based contracts. Gradually, the buyers and suppliers will own a portfolio of market-based contracts and other assets.

Transition Using Vesting Contracts

In the mid-1990s, the Australian State of Victoria underwent electricity deregulation. Simultaneously, the government imposed vesting contracts that provided generators with a substantial part of their revenues at predictable prices for transitional periods of two to five years. One of the motives for deregulation in this region was the high cost of installed overcapacity in electricity generation, which was a consequence of large investments in coal stations by government-owned utilities as well as supply-side efficiency improvements. As a result, electricity prices in Australia fell by around 15 per cent in real terms over the decade to 1997-1998. Initially, the vesting contracts that had been put in place had much higher prices than pool prices, but this situation reversed in later years. In effect, the government-imposed vesting contracts shielded privatized generators from potentially severe financial losses, which could have developed from a short-term exacerbation of oversupply. (Kee 2001) Without the vesting contacts, privatized generators would have had no motivation to participate in the marketplace and there would have been a long-term shortage of generation. Following the initial period of oversupply and depressed prices, by 2001, these same markets suffered supply shortfalls and soaring spot market prices. The sudden rise in prices lead to closure of several major industrial facilities, primarily aluminum smelters. This type of "boom and bust" cycle of power development is not unlike similar cycles in other unregulated commodities such as oil and natural gas, or, for that matter, real estate development.

Conversely, failure to manage these transitions can be expensive. Rockland Electric has incurred significant risks due its failure to use short-term parting contracts effectively.

Transition without Vesting Contracts

In 1998, prior to deregulation in New York, Rockland Electric Company (RECO) entered into a short-term parting contract with the purchaser of its generating assets. Other New York utilities faced with the same market uncertainties took steps to manage/hedge short-term pricing risk. Most entered into longer-term transition power agreements (as parting contracts are called in New York) and other agreements that provided for significant amounts of supply for several years after generation divestiture, at prices that were at least partly fixed. New York State Electric and Gas (NYSEG), Central Hudson, and Niagara Mohawk all entered into parting contracts in 1998, 1999, and 2000 of at least two years in duration. Such contracts reduced their exposure to the spot market.

RECO and its customers, on the other hand, were completely exposed to short-term price volatility. As a result, RECO had unusually large costs for buying power in 2000. The company accrued excessive amounts of deferred balances, which are losses accumulated by utilities when the cost of purchasing electricity exceeds the capped rates they are allowed to charge customers. New Jersey's Electric Discount and Energy Competition Act (EDECA) requires that ratepayers reimburse utilities "on a full and timely basis all reasonable and prudently incurred" deferred balances.

However, there is currently a hearing to determine if balances in these accounts could have been avoided through longer contracts of 2-4 years. In fact, RECO could lose up to $20-30 million in this case, which it could have avoided by better managing electricity price risks. For example, a multi-year parting contract covering perhaps 50 percent of the Company's expected requirements would have been consistent with the Company's subsequent hedging approach, which called for hedging approximately 50% of its generation requirements. Unfortunately, by the time RECO had changed its procurement practices, prices had already risen, and the opportunity of a built-in hedge in the form of longer-term parting contracts had been lost.

A.4 Consideration of Contract Types

In Chapters 4 and 7 of this report, we reviewed the range of commodity contract structures and related financial hedging tools, both in the abstract and as applied to the electric industry. Here we will consider how those devices translate for use in electric default service portfolio management. This subsection begins with an overview of the types of market-based contracts that should be considered in assembling a portfolio.[55] We then provide a similar overview of financial hedging transactions and discuss how both types of transactions apply in PM. One special issue regarding reliance on contracts—contract disputes and enforceability—is also discussed briefly.

Long-term electricity contracts generally treat fuel price risk through one of three pricing mechanisms: (1) fixed prices, (2) indexed prices, or (3) "tolling" agreements.

[55] In addition to those discussed here, a very large number of contract types exist for what are usually called ancillary services. Ancillary services include, for example, generating reserves needed to ensure reliability and provision of units capable of being slowed down or speeded up to maintain proper 60 Hz power frequency. They are often traded as customized bilateral contracts (as is done in the class of resource-based contracts), and broker-mediated contracts. These types of services and contracts are beyond the scope of this report.

Forward Contracts

Forward contracts are the most traditional of the contractual instruments available for current PM. In a forward contract, the Buyer contracts with the Seller to take delivery of a specified amount of power at a certain location on the grid at specified times and prices. The power may or may not include ancillary services, such as capacity credit, or attributes, such as emissions tags or renewable energy credits.

Fixed-price electricity contracts typically establish a fixed and known price per MWh of delivered electricity. Alternatively, the price per MWh may vary according to a fixed schedule; the key point is that the price does not vary with market conditions. Such contracts clearly allocate fuel price risk to the Seller because the Seller is responsible for selling electricity at fixed prices while simultaneously dealing with a variable fuel price stream. The Buyer presumably pays a premium for fixed-price contracts because the Seller has to manage the fuel price risk to which it is exposed, which increases the Seller's costs. If the Seller does not adequately mitigate its exposure to fuel price risk it will be more likely to default on the contract, however, so the Buyer is left with some "residual" fuel price risk (i.e. contract default risk) with fixed-price non-renewable contracts. Conversely, the Buyer gives up certain opportunities to take advantage of favorable fuel price changes, and typically must take a specified (or minimum) amount of power whenever it is provided for in the contract, regardless of variations in the utility's load. This obligation to "take and pay," regardless of need for the power, is the reason that rating agencies impose a "debt-equivalent" penalty on the buyer when this type of contract is used.

Indexed-price contracts generally index the price of electricity to either inflation or to the cost of another commodity, for example, the cost of the fuel used to generate the electricity (Kahn 1992). When indexed-price electricity contracts are indexed to the price of the fuel used to generate the electricity, the fuel price risk is allocated to the Buyer because the Buyer receives a variable-priced product. Fuel price risk can be managed using financial hedging instruments. This type of contract causes a smaller "debt-equivalent" penalty for the Buyer, because the price paid is more likely to reflect the market value, meaning the utility can dispose of any surplus and recover most or all of the cost.

Demand and Energy contracts combine the features of the fixed-price and indexed-price contract forms. In this type of contract, the Buyer pays a fixed amount each month for the right to the take power (intended to represent the fixed costs incurred by the Seller), and then a charge per kilowatt-hour actually taken (representing the variable costs incurred by the seller.) The variable charge may be fixed or constrained, but is often indexed to a market price for fuel. This type of contract is more difficult to hedge, because the quantity of power to be taken cannot be known in advance by either the buyer or the seller.

Tolling contracts require the Buyer of the electricity to pay for the cost of the fuel used to generate the electricity (and sometimes other variable operating costs or uncontrollable costs), and the Buyer may also have the option of providing the fuel itself. Tolling agreements and fixed-price agreements conceptualize the service and product being provided by the Seller to the Buyer in fundamentally different ways. In fixed-price contracts, the Seller clearly sells the Buyer a product: electricity. In tolling agreements, on the other hand, the Seller is effectively providing the Buyer a service: the right to use the Seller's power plant to convert fuel to electricity. The Seller is paid not only for the use of its facility, but also for simply being available to generate (through a reservation, or "capacity" charge). In addition, the Buyer pays for the fuel used to generate the electricity. The risk of fuel price variability is therefore clearly allocated to the Buyer in tolling contracts. The Buyer can then choose to reduce its fuel price risk exposure through fixed-price physical fuel supply contracts, fuel storage, or financial hedging instruments.[56]

In general, long- and short-term forward contracts provide some of the security and stability utility-owned resources, and warrant consideration for inclusion as a significant portion of a default portfolio because these are traits that ratepayers are comfortable with and value.

Of course, over-buying forward contracts when prices and demand are uncertain can result in losses or rate pressure. Therefore, techniques such as laddering of contracts and diversification of technologies, fuels and suppliers should be pursued. Careful analysis of load forecasts and price projections should be used to establish a reasonable percentage of expected load to be met by long- or short-term forward contracts and which types should be included. Just as an investment portfolio should avoid too much investment in a single industry or single company, a power portfolio should avoid too much commitment to any specific fuel or generating unit.

Long-Term Resource-Based Forward Contracts and Renewable Generation

In contrast to fossil fuels, renewable resources typically have a less-variable (or even free) fuel cost stream, resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas-generated electricity.

Since the use of renewable resources decreases fuel price risk for both parties to a contract, all else equal, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas-generated electricity. This is because the Buyer of a fixed-price gas-fired contract (if such a contract is available) may still bear some residual fuel price risk through potential contract default by the Seller if natural gas prices increase, as discussed above.[57] Experience shows that the risk of contract default or renegotiation in such cases can be significant for gas-fired contracts (EIA 2002), though the magnitude of this risk is difficult to assess with precision and therefore deserves additional analysis. (Bachrach, 2003)

---

56 Arrangements for operating costs other than fuel may vary.

57 Such counterparty risks exist in all markets, but in mature markets for standardized instruments, such as those discussed in Ch. 4, they are carefully minimized by trading rules of exchanges through practices such as daily settlement of value changes. See for example, CME 2003 and Culp 2001, p. 272.

Forward contracts are essentially the same instrument as the firm power contracts that have been traded bilaterally among utilities since the first interconnections between them. Those contracts now exist in a somewhat different environment. Since Order 888, they are no longer (usually) FERC-regulated cost based contracts or power pool mediated split the savings deals, but "market priced."[58] In many markets, brokers offer a kind of matchmaking service, posting ask and bid prices for standardized blocks of power for various time periods, e.g., monthly for two years and semi-annually for five years, but actual transactions take place between individual counterparties. Actual future contracts--fully standardized contracts traded anonymously on exchanges that provide regular clearing services--are now available on a number of commodity exchanges around the country.

[58] As discussed elsewhere in this report, this lack of wholesale price regulation does not mean that all such contracts are arm length transactions reflecting the economic valuation achieved in efficient free markets. Default service providers, who one way or another, continue to have effectively captive customers should be required to avoid any apparent or actual conflicts in trading, especially with affiliates.

Appendix B. Energy Efficiency Cost-Effectiveness Tests

B.1 Definition of Tests

The costs and benefits of energy efficiency are sometimes different from those of supply-side resources, and have different implications for different parties. As a result, five tests have been developed to consider efficiency costs and benefits from different perspectives. These tests are described below and summarized in Table B.1.[59]

- The Participant Test. The goal of this test is to determine the impact of efficiency on the customer that participates in the efficiency program. The costs include all the expenses incurred by the customer to purchase, install and operate an efficiency measure. The benefits include the reduction in the customer's electricity bills, as well as any financial incentive paid by the utility. This test tends to be the least restrictive of the other tests, because electric rates tend to be higher than avoided costs, and participating customers see the greatest benefit from the efficiency programs.
- The Energy System Test.[60] The goal of this test is to determine the impact of efficiency on the total cost of providing electricity (or gas, in the case of gas utilities). This test is most consistent with the way that supply-side resources are evaluated by vertically-integrated utilities. The costs include all expenditures by the utility (or program administrator) to design, plan, administer, monitor and evaluate efficiency programs. The benefits include all the avoided generation, transmission and distribution costs.
- The Total Resource Cost (TRC) Test. The goal of this test is to determine the total cash costs and benefits of the efficiency program, regardless of who pays and benefits from it. The costs include all the expenditures by the utility (or program administrator), plus all the costs incurred by the customer. The benefits include all the avoided utility costs, plus any other cost savings for the customer such as avoided water costs, avoided oil costs, reduced operations and maintenance costs to the customer, or non-energy benefits to low-income customers. For most efficiency measures, this test tends to be more restrictive than the Energy System Test, because customer contributions to energy efficiency measures are easier to identify than additional benefits not considered in the Energy System test.
- The Societal Cost Test. The goal of this test is to determine the total costs and benefits of efficiency to all of society, including more difficult to quantify benefits such as environmental benefits and economic development impacts. The

59 These tests are defined slightly differently by different Public Utilities Commissions. For the most comprehensive description and discussion of these tests, see CA PUC 2001 and LBL 1988.

60 This has previously been referred to as the Utility Cost or the Program Administrator test.

costs and benefits are the same as for the TRC Test, except that the benefits also include monetized values of environmental and economic development benefits. If environmental and economic development benefits are properly calculated, this test tends to be the least restrictive of them all, with the possible exception of the Participant Test.

- The Ratepayer Impact Measure (RIM) Test.[61] The goal of this test is to determine the impact on those customers that do not participate in the energy efficiency programs, by measuring the impact on electric rates. The costs include all the expenditures by the utility, plus the "lost revenues" to the utility as a result of having to recover fixed costs over fewer sales.[62] The benefits include the avoided utility costs. This test tends to be the most restrictive of all the efficiency tests, because the lost revenues have a large impact on the cost calculation.

Table B.1. Components of the Energy Efficiency Cost-Effectiveness Tests

	Partici-pant Test	Energy System Test	TRC Test	Societal Test	RIM Test
Energy Efficiency Program Benefits:					
Financial Incentive to Customer	X	---	---	---	---
Customer Bill Savings	X	---	---	---	---
Avoided Generation Costs	---	X	X	X	X
Avoided Transmission and Distribution Costs	---	X	X	X	X
Resource Benefits (e.g. oil, gas, water)	---	---	X	X	---
Non-Resource Benefits (e.g. O&M savings)	---	---	X	X	---
Benefits to Low-Income Customers	---	---	X	X	---
Environmental Benefits	---	---	---	X	---
Economic Benefits	---	---	---	X	---
Energy Efficiency Program Costs:					
Program Administrator Costs	---	X	X	X	X
Participating Customer Costs	X	---	X	X	
Lost Revenues to the Utility	---	---			X

B.2 Shortcomings of the RIM Test

The RIM test should not be used as the primary tool for determining the cost-effectiveness of energy efficiency programs for the following reasons.

---

61 This has previously been referred to as the Non-Participant test and the No-Losers test.

62 In some situations, efficiency program outlays and customer bill savings can result in secondary sales growth that can offset some of these "lost revenues." Such rate lowering effects of program driven secondary sales are usually counted in support of economic development discount rates and should be considered here as well.

- The RIM test will not result in the lowest cost to society.
- Rate impacts and lost revenues are not a true cost to society. Rate impacts and lost revenues represent a "transfer payment" between non-participants and participants. Consequently, they are not a new cost, and should not be applied as such in screening a new energy efficiency resource. Rate impacts and lost revenues may create equity issues between customers. However, these equity issues should not be addressed through the screening of efficiency programs, but through other means, as described below.
- Screening efficiency programs with the RIM test is inconsistent with the way that supply-side resources are screened. There are many instances where utilities invest in new power plants or transmission and distribution facilities in order to meet the needs of a subset of customers, (e.g., new residential divisions, an expanding industrial base, geographically-based upgrades). These supply-side resources are not evaluated on the basis of their equity effects, nor are the "non-participants" seen as cross-subsidizing the "participants." Energy efficiency resources should not be subject to different screening criteria than supply-side resources.
- Consumers, in the end, are more affected by the size of their electric bills (the product of rates and usage) than by the rates alone. The RIM test does not provide any information about what happens to electric bills as a result of program implementation.
- A strict application of the RIM test can result in the rejection of large amounts of energy savings and large reductions in many customers' bills in order to avoid very small, *de minimus* impacts on non-participants' bills. From a public policy perspective, such a trade-off is illogical and inappropriate.

Even if the RIM test is not used to screen energy efficiency programs, there are two remaining rate effect issues that may be of concern to utilities and policy-makers: the potential importance of rate impacts of any size and concerns about equity between efficiency program participants and non-participants. These two issues are discussed in Chapter 6 of this report.

Appendix C. Distributed Generation Technology Characteristics

While any generating technology can be considered for distributed applications if it lends itself to small, dispersed installations, certain technologies have greater promise for DG.

- **Fuel cells** produce electricity and heat by combining fuel and oxygen in an electrochemical reaction and can operate on a variety of fuels including natural gas, propane, landfill gas, and hydrogen. Their direct conversion of chemical energy into heat and electrical energy offers quiet operation, low emissions, and high efficiencies. With present technologies, fuel cell electrical efficiencies range from 40% to 60%, and their combined electrical and heat efficiencies are over 80%, and provide highly reliable, premium quality power. Presently, the cost of fuel cells are relatively high at about $3,000 per kW, but are expected to become considerably lower under mass production.
- **Microturbines**, small gas turbines, with only one moving part, range in size from 30kW to several hundred kW and operate on a variety of fuels including gasoline, diesel, and natural gas. Microturbines are quiet, readily dispatchable, and well suited for commercial and industrial applications. First generation microturbines yield relatively low efficiencies of about 30%, but also have moderate capital costs of around $600/kW. It is anticipated that microturbines that are fueled by natural gas, without cogeneration, will produce electricity for 7 cents to 10 cents per kWh making them competitive with the combined cost of utility generation and distribution service in the near term.
- **Photovoltaic (PV**) devices convert directly sunlight into electricity and are modular, lightweight, contain no moving parts (unless tracking devices are used), release no emissions, need no water, and have low operation and maintenance requirements. Photovoltaic panels can be placed on rooftops giving this technology significant siting flexibility. However, small unit PV installations remain relatively costly at about $5,000/kW installed. (DOE 1997) PV installations require relatively large areas to produce significant amounts of power. The most common applications of PV technology to date have been to power small loads in remote, off-grid sites where utility line extension costs are prohibitive. As photovoltaics become more widely used, it is anticipated that resulting mass production will lead to significant price decreases. Some states have provided favorable tax rules for such investments. (IREC 2003)
- **Reciprocating engine/generator sets** run on a variety of fuels, come in sizes from 5kW to tens of MW with installed costs from $500/kW to $1,500/kW. These mass produced sets are supported by established sales and maintenance infrastructures, and are available as residential and commercial cogeneration packages. Drawbacks include relatively high emissions, noise, and maintenance requirements.

- **Wind Turbines** have been the subject of recent, ongoing technological advances have increased their efficiency and reliability while lowering their costs. Installed costs for wind turbines range from \$1000/kW to \$3000/kW. Adaptations to cold, icing environments has also made progress. While wind turbines have no fuel requirements and zero emissions, they typically produce power at only 30-40% of their rated capacity and can have site-dependent noise, wildlife habitat, and visual aesthetic concerns.
- **Storage Technologies**, the most common being the battery, store energy in chemical or mechanical form and like other storage devices can be used for peak shaving, spinning reserve, outage support, and voltage and transient stability. While not yet viable for storing large amounts of energy, batteries are currently used for uninterruptible power supplies, support for off-grid PV and wind systems, and emergency backup for lighting and controls. Other options include compressed air storage, pumped hydroelectric storage, and more exotic technologies such as flywheels and superconducting rings, both of which remain experimental.

In addition to the PM benefits cited above for ownership of physical generation, in general, distributed generation (DG) provides certain additional desirable features. DG development can, of course, defer or eliminate local and inter-regional T&D additions and upgrades with consequent capital and O&M savings and concomitant avoided investment risks. Additional T&D benefits of DG include reduced line losses, better voltage support, and improved power quality and reliability (with associated improvements to customer relationships). DG development can also deliver non-T&D benefits. These include new business opportunities in an emerging competitive market and reduced environmental impacts. This can bring improved public relations by "greening" the products of both the provider and the DG host customer. DGs greater modularity allows new capacity to follow load growth more closely and reduces the impact of outages. Finally, cogeneration placed on customers' premises promotes local economic development and other investments in the local community.

DG resources are most often installed at the distribution level and can be on either side of the meter. They are typically small, ranging from less than one kilowatt (kW) to only a few hundred kW, but much larger installations can be important in commercial and industrial settings.

On occasion, units of hundreds of kW up to 100 or more MW may be relevant where the capacity constraints being addressed are on the transmission or subtransmission level. Because transmission systems are designed for "n-1" reliability, maintaining service with one line out, there may be a number of conditions when a distributed resource will eliminate the need for a major transmission investment needed to secure a secondary transmission path that would seldom be needed.

On the supply side, gasoline and diesel fueled reciprocating engines have well-known cost and performance characteristics, while micro-turbines and fuel cells are more novel, but have potential advantages where air quality and power quality requirements are critical. Advancement in the efficiency, reliability, cost and maintainability of advanced technologies may be expected to continue and screening choices should be reviewed frequently.

In passing, it is worth noting that, the full range of DSM options also applies--both lost opportunity programs targeting new construction, renovation, and equipment replacement events and retrofit measures. Lost opportunity programs can be particularly cost-effective where T&D constraints are driven by rapid load growth. In areas with strongly seasonal peak loads, efficiency and load control measures that target the times feeder, substation, or regional loads peak should receive priority attention. Relevant DSM measures include: 1) efficient appliances, lighting, heating, and industrial processes; 2) utility or energy service provider control of specific customer loads; and 3) rate designs such as inverted rates, time-of-use rates, interruptible rates, and real-time pricing. Coordination of programs with ISO or RTO demand response offerings can improve cost effectiveness.

Interconnection of distributed generation has often presented technical and institutional barriers to development. Developers and participating customers need reasonable and predictable policies and interconnection rates and fees. Those requirements have only recently begun to be met in any widespread fashion. Regulators should act to ensure that these barriers are minimized. Recent adoption of a technical standard for generator interconnection by the IEEE should significantly improve the situation, as did an earlier standard for photovoltaic device interconnections.[63]

[63] For example, IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, adopted June 12, 2003. See, http://www.eere.energy.gov/distributedpower/news/0603_ieee1547.html

Appendix D. Methods for Analyzing and Managing Risk

D.1. Risk Measurement Tools for Assessing Portfolios

When comparing electricity portfolios, we would like to be able to quantify and compare the risk of each portfolio. Similarly, when issuing an RFP for electricity supply, we would like to be able to specify a desired quantitative level of risk and to compare riskiness (to consumers) of bids.[64] There are ways to quantify many but not all of the risks that need to be evaluated. Even where there is an appropriate methodology, however, the availability of data may be limited. An introduction to this task was given in Section 9. Here, we review the primary quantitative methodologies for quantifying portfolio risk.

Risk measurement begins with a thorough assessment of the full spectrum of risks that affect each resource in the portfolio and that need to be addressed in planning. (Gleason 2000) This assessment should include a careful search for risks that are correlated with each other. Once risks have been identified, historical data and other sources should be used to quantify the magnitude and probabilities of those risks, as well as their correlation with each other. With that information in hand, there are several techniques for evaluating how those risks interact to form the risk profile of a portfolio.

When the relevant sources of variability are quantified for each portfolio component, the overall variability of the portfolio can be derived mathematically, at least for those quantified risks. The major complication to this task is that method for combining standard deviations of the components depends on how closely correlated are the fluctuations of the various components. This is quantified by the covariance of the component prices. For simple cases where there is historical data for the correlation of costs, such as for natural gas and oil, this effect can be computed directly. (Gropelli and Nikbakht 2000, p. 91) In other instances, simulation modeling may be needed. Finally, the techniques for estimating the effect of options and futures on the variability of portfolio costs are complex, but should be used where appropriate. (Trigeorgis 1996) Discussion of those techniques is beyond the scope of this report. Furthermore, there has been very little published research on application of these methods to electricity markets.

Nominal Exposure Report

A nominal exposure report is an analysis, for each broad type of portfolio component, of that component's dollar value and the amount of that dollar value that is exposed to loss.

[64] It is important to keep in mind that risk is a property of *both* an entire portfolio *and* the portfolio's component parts. That is to say, each resource in the portfolio will have its own level of volatility, counter-party risk, and so on, but the overall riskiness of the portfolio is *not* a linear sum of those risks. Depending on how closely correlated the various risks are, the overall portfolio may or may not be less volatile than the individual assets contained in it.

It is a snapshot of a particular risk exposure at a moment in time giving the amount of value that is *exposed* to loss, but does not represent the amount of loss that *could occur.* The latter amount is determined by other methods. (Culp, 2001)

Stress Testing

Stress testing a portfolio involves simulating different market conditions for their potential effects on the portfolio value. The basic question for a stress test is: how much loss might occur in the event of a crisis? In general, there are two methods used to answer this question. First, one can test the portfolio relative to historical shocks and see how the current portfolio might fare in a similar situation. The second approach is to brainstorm extreme scenarios and test their affect on the portfolio. The problem with these approaches is that history is unlikely to repeat itself exactly, and nobody can predict the future. Nonetheless, stress testing allows the portfolio manager to better understand how much loss might occur during a catastrophic event.

Mark-to-Market

Another approach to monitoring a managed portfolio is known as mark-to-market accounting. In this, periodically (as often as daily), one adjusts the value of the portfolio based on gains/losses in current market value of the assets relative to book value. The hope is that gains/losses are within the risk bounds of the portfolio owner. If they are not, one can try to rebalance the portfolio to better control risk. Mark-to-market is designed to show the full extent of a company's liabilities/risks over a period of time so that investors have no unwarranted surprises. While current market values are reported using this technique, actual realization of cash is unaffected. The same techniques applied to an electricity portfolio will provide evidence of whether consumers are exposed to unwarranted surprises in electricity costs.

Uncertainty Analysis Using Simulation

In practice, uncertainty analysis remains an evolving discipline for power supply portfolio planning. There is a paucity of applicable historical data for computing variances and covariances of prices and demands for both forward and option positions, and the multitude of physical supply- and demand-side alternatives is quite large compared to most financial markets. In addition, these alternatives, unlike those in most financial markets, have dimensions that go beyond price and price volatility.

Physical generation and DSM alternatives all have various unique risks that may or may not be well known, but they also have numerous qualitative costs and benefits not easily captured in costs, even societal costs. Some of these, such as cancellation rights, modularity benefits, and market power mitigation effects can, in principle, be evaluated as real options or assessed through dynamic programming. (Trigeorgis, 1996; Dixit and Pindyck, 1994)

In general, the current state of the art involves either scenario analysis, bounding case analysis, or simulation modeling using randomized inputs.[65] Uncertainty analysis allows one to determine which factors most affect a diversified portfolio. The manager can then focus on monitoring these factors and reducing the relative importance of them in the portfolio through diversification.

Decision Trees and Real Option Analysis

Decision tree analysis (DTA) is a traditional, systematic, and rational mathematical method for structuring and analyzing managerial decision problems in the face of uncertainty. It is most useful where there are a series of complex decision to be made at a sequence of points in time. (Trigeorgis 1996) At each point, options exist and, for each option, various uncertain outcomes can occur before the next decision point. The decisions available at each option point and the resulting possible outcomes from each then form a tree of contingencies. The decision points can be dates at which various portfolio additions could be chosen, and the uncertain outcomes would be the ensuing market conditions, for example. Once the relevant branches have been identified, each with its own sequence of decisions and outcomes for the uncertain variables, they can be evaluated one by one to determine the total cost of each of the available sequences of decisions given each of the possible outcomes on the uncertainties. This is a lot of arithmetic, but straightforward in principle. The various outcomes can be examined for insights into the possible results for each initial decision. Further, if probabilities can be assigned to each of the uncertainties, DTA becomes much more illuminating. Expected results for each initial decision can be computed that capture reasonably well the dynamics of decisions over time in the face of uncertainty. (Trigeorgis 1987, Houston P&L 1988, NEES, 1993)

Sensitivity and Scenario Analysis

People use models to gain insight into possible future outcomes. They then often take action based on the model's results. However, in order to take action, the decision maker should be fully confident that the model's results are robust – that small changes in the model's key variables will not yield extremely different outputs. It is also important to assess how well a candidate strategy can be expected to perform under different possible future trends.

Sensitivity analysis is performed in order to test the degree to which a model's results might vary as a result of both small and large changes in the value of each key variable used in the model. Originally, sensitivity analysis was created to deal simply with uncertainties in the input variables and model parameters. Over the course of time the ideas have been extended to incorporate model conceptual uncertainty, i.e. uncertainty in model structures, assumptions and specifications. Using sensitivity analysis, the portfolio

[65] Both Monte Carlo or Latin Hypercube simulation model the effects on a portfolio of variations in a few key drivers. (Culp 2001, McKay 1979; Iman 1985) A computer simulation is run hundreds or thousands of times, varying each uncertain variable. One can then view the statistics of the simulated model and the resulting variability of particular outcomes.

manager is able to see how the optimal portfolio strategy is affected by changes in the values of key variables. The manager can then increase robustness/confidence by reformulating the model, such that the model's results remain firm under slightly changing conditions. Equally important, it is possible to evaluate, for each uncertain input factor, how much the forecasted results vary. This can provide insights for redesigning strategies and guidance for which input factors require the most careful monitoring.

Scenario analysis is similar to sensitivity analysis, but focuses on understanding how well a candidate strategy (or portfolio) can be expected to fare under significant excursions in the input variables. This is a model-driven form of stress testing and has long been used in IRP. In its longest standing form, scenario analysis begins by taking the forecaster's base case--the one that reflects the most likely versions of the future--and defining an uncertainty band around the most import input variables, often load forecast and fossil fuel prices. If especially relevant, a utility would sometimes also consider the best and worst potential availability factors for a large power plant, production rates for an especially large customer, or other unique factors important to its performance. Then, a few mutually compatible but extreme bundles of these input assumptions would be used as assumptions in the modeling instead of the base case. For example, a utility might consider how its portfolio would perform if its largest plant were out twice the normal hours/year and oil prices were at the high end of the spectrum, while load was at the low end of its likely band.

More recently, a new style of scenario planning has become common in the corporate world and is making some inroads in the electric industry. (Platts 2002) Intended to help planners in times of rapid change, scenario planning uses rigorous, disciplined analysis to develop narratives that describe what *may* happen in the form of intentionally divergent futures with sweepingly different social, political and economic natures. Quantitative models then use each of theses self-consistent but radically incompatible sets of input assumptions to test the robustness of various strategies. In a sense, this approach strives to hit the strategies with "bigger hammers" than traditional sensitivity studies to see what "breaks." By examining the results, strategies can be developed that may not be the best under any one future, but are survivable in all of them.

Summary

This section has reviewed a range of techniques for analyzing portfolio risk. The simplest to implement are the Nominal Exposure Report (which measure the amount of value that is exposed to risk, but not the magnitude of the loss that could occur) and Stress Testing (which estimates the impact of selected extreme outcomes in the market). These techniques can provide useful insight and do not require complex modeling and technical resources, but do not provide explicit, quantitative estimates of portfolio risk. Mark to Market is also straightforward to implement, but is a method for monitoring the ongoing value of a portfolio, not assessing its risk level; it is a management tool, not a planning or selection tool. Sensitivity Analysis (where portfolio performance is modeled under a variety of possible futures to identify and quantify potential weaknesses and strengths) is somewhat more demanding, in that some outcome modeling is needed, but begins to provide the information needed to reasonably compare portfolios for risk. If reasonable historical data or sound estimates of probabilities for different driving events, such as price excursions and outages, are available, Sensitivity Analysis can quantify the expected magnitude of risk. Proper application of this and the more complicated techniques covered in this section demand considerable experience and familiarity with the decision making context. Simulation Analysis and Decision Tree Analysis are two techniques that can be readily applied in simple cases, but become daunting when risks are numerous and complex. Their main advantage is that the can provide explicit, quantitative estimates of expected outcomes *and* the probability of better or work outcomes. Real Option Analysis is the most demanding method mathematically, but adds specific quantification of the value contributed by maintaining flexibility and reducing risks, a benefit not provided by other modes of analysis.

Each portfolio manager and regulators overseeing portfolio management should consider the resources available and select an appropriate level of investment in uncertainty analysis and portfolio risk assessment, given the planning and operating environment and the resources available. The most important tools for this work are an open minded approach to risk identification and careful analysis of which risks are correlated and which are not.

D.2 Efficiency Frontiers and Portfolio Optimization

Imagine you need to assemble a ten-year supply portfolio from a few dozen available supply alternative, all available in whatever quantities and lifetimes you wish. Each alternative has a known upfront cost and an annual capacity cost (either known or uncertain or mixture). You have forecasts of the future variable costs of power from each alternative, but for some alternatives this is quite uncertain. Some alternatives are also subject to unpredictable outages (which may occur at any time and may or may not be permanent). Some alternatives are also subject to regulatory or capital costs of uncertain amounts that may or may not be imposed, but could be significant and some guesses are available for what those costs might be *if* they occur. The actual amount of power needed for the next ten years can be forecast, but growth rates could range from zero to twice your forecast and can bounce around considerably from year to year, depending on weather and the economy (which also affect the variable cost of power, by the way). Certain hedging instruments are also available if you wish to use them, and it is expected that more such instruments will become available over time. How would you choose the "best" portfolio from among these alternatives?

This is the portfolio optimization problem. Even with the simplifications used above, it is clearly challenging. Yet it is essentially the same problem that most manufacturers face. Determining how much to invest in each asset in such a portfolio in order to minimize risk while minimizing expected cost can, in principle, be formulated and solved mathematically.[66] We will make a short diversion to look at the analogous similar problem of managing an investment portfolio where the goal is to maximize return on

[66] This would generally be a nonlinear optimization model, likely a dynamic, multi-period one

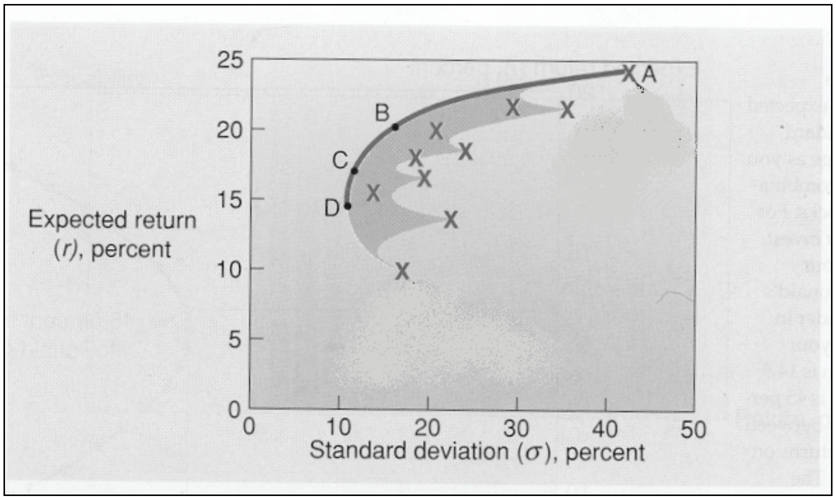
investment while minimizing risk.[67] In that field of study, a model, known as the efficiency frontier model, is helpful for guidance.

Now, let's imaging that a number of adequate candidate portfolios have been put together. Using the forecasts mentioned above and their error bounds or uncertainties, each candidate portfolio can be given an expected return and a measure of how uncertain or variable that return is (the standard deviation of the portfolio's return). Let's plot each candidate portfolio as a point on a graph where the vertical axis is the expected return and the horizontal axis is the variability of that return. (Figure D.1 shows an example.) What will usually be seen is that for each degree of variability (risk) shown as a location on the horizontal axis, there will be some portfolio that has the best (highest) return. (Some of these are marked A, B, C, and D in the figure.) A line connecting these "best of breed" portfolios is called the *efficiency frontier*. One will always prefer portfolios along that line. These are efficient portfolios because they offer maximum expected return, at each given risk level.

Although the process of computing the efficiency frontier is theoretically straightforward given a particular set of resource options and given levels of uncertainty in prices and demands, there are difficulties to using the efficient frontier in practice. Namely, the efficient frontier is computed based on future expected returns and future standard deviations and covariances among portfolio assets. Unfortunately, it is difficult to predict what these future values will be. One has to be careful that the optimization model that is supposed to minimize the risk of the portfolio will not turn out to be minimizing noise only. As a practical matter, planners typically resort to one or more of the uncertainty analysis methods described below, but it is worthwhile to remember that what we are trying to do is find that efficiency frontier and select a point along it that best suits our valuation of risk. It is also important to remember that we should always be on the lookout for new alternatives that could result in lowering the risk of a portfolio (moving it to the left on this graph) or its cost (moving it down).

[67] In the IRP or default service provider PM contexts, it may be best to think of the objective function (the measure of a portfolio's success) as being the life cycle societal cost or life cycle total resource cost of the portfolio and seek to minimize that value, but this subsection will cast the argument in terms of maximizing return. While there is usually a starting point portfolio and a variety of outlays (purchase commitments, construction investments, hedging expenditures, and so on) that might improve the life-cycle cost, the cost of which may be compared to the resulting savings to derive a "return" to be maximized, this may overcomplicate the analysis.

Figure D-1. Example of an Efficiency Frontier



Efficient portfolios: each cross represents the expected return and risk of individual investments. The shaded area shows the possible combinations of expected return and risks from investing in a mixed portfolio. One will always prefer portfolios along the upper, heavy line. A, B, C, D represent efficient portfolios because they offer maximum expected return, at a given risk level. Describe special considerations in integrating supply and demand-side options.