

2006



Energy Portfolio Management: Tools & Resources for State Public Utility Commissions

NARUC

**The National
Association
of Regulatory
Utility
Commissioners**

**Prepared by Synapse Energy
Economics**
For Consideration by
**NARUC, NYSERDA, The Energy
Foundation, and the U.S.
Department of Energy**

Energy Portfolio Management:

Tools and Practices for Regulators

Prepared by:
William Steinhurst, David White,
Amy Roschelle, Alice Napoleon,
Rick Hornby, and Bruce Biewald
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

For the Consideration of
The National Association of
Regulatory Utility Commissioners

October, 2006

DISCLAIMER

This report was prepared as an account of work sponsored by the National Association of Regulatory Utility Commissioners through the support of the Energy Foundation, the New York State Energy Research and Development Authority, and the United States Department of Energy. Neither the U.S. Department of Energy, the Energy Foundation, the New York State Energy Research and Development Authority, and the National Association of Regulatory Commissioners (NARUC), nor any person acting on their behalf:

- A. Makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately-owned rights.
- B. Assumes any liabilities with the report as to the use, or damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference therein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the U.S. DOE. The views and opinions of authors expressed therein do not necessarily state or reflect those of the U.S. DOE.

The views and recommendations in this report do not represent NARUC policy positions, though some report recommendations may coincide with existing NARUC policy positions.



Table of Contents

1. Introduction and Summary	1
1.1. Background and Purpose	1
1.2. What is Portfolio Management?	3
1.3. How Might PM be Applied to Particular Retail Electricity Markets?.....	5
1.4. Key Conclusions	6
2. Portfolio Management: Objectives and Applications.....	9
2.1. Portfolio Management Can Be Used to Achieve Public Policy Objectives in a Transparent Manner	9
2.2. Portfolio Management Can Be Applied under Any Market Structure and Regulatory Framework	10
2.2.1. Application of Portfolio Management in Fully Regulated Markets	11
2.2.2. Applying PM in Retail Competition Markets	12
2.3. Portfolio Management Provides a Process and Set of Tools for Examining Complex Resource Planning and Procurement Issues.....	13
3. Confronting Uncertainty and Risk.....	16
3.1. Two Contexts for Portfolio Management	16
3.2. Integrating IRP and PM Concepts	17
3.3. Organizational Issues	19
3.4. Making and Communicating Choices about Risk Management.....	20
3.5. Techniques for Analyzing Risk Exposure and Uncertainty.....	22
3.5.1. Measuring Risk and Expected Benefit	22
3.5.2. Considering Risk in the Assessment of Resource Choices	27
3.5.3. Tools for Mitigating Risk	28
4. Tools and Data for Portfolio Management.....	29
4.1. Overview.....	29
4.2. Tools Available for Portfolio Management	29
4.2.1. Load Forecasting	30
4.2.2. Price Forecasting	31
4.2.3. Integrated System Planning.....	31
4.2.4. Risk Analysis.....	31
4.2.5. Managing Financial Resources and Contracts	31
4.3. Strengths and Deficiencies of Tools for Resource Planning and Procurement 32	
4.4. Things to Consider Before Selecting Software.....	33

4.5. Data Requirements for PM	34
5. Expertise and Staffing for Portfolio Management.....	36
5.1. Staffing and Expertise for Portfolio Managers	36
5.2. Staffing and Expertise for Regulators.....	37
6. Conclusion	38

**Appendix A: Supply Acquisition Strategies For Default Service In States With
Retail Access**

Appendix B: Integrated Resource Planning Practices in Regulated States

Appendix C: Models and Tools for Portfolio Management

Appendix D: Risk Measures

Acknowledgments

The authors would like to thank the National Association of Regulatory Utility Commissioners, the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, the New York State Energy Research and Development Authority, and the Energy Foundation for funding this effort. We would also like to thank the following individuals for their invaluable comments on drafts of this report.

Raj Addepalli, New York Department of Public Service

Barbara Alexander, Consumer Affairs Consultant

Annunciata Marino, Pennsylvania Public Utility Commission

Nicolas Garcia, Washington Utilities and Transportation Commission

Frank Graves and Phil Hanser, The Brattle Group

Cheryl Harrington, Regulatory Assistance Project

Jerrold Oppenheim, Consultant

Richard Rosen, Tellus Institute

Commissioner Richard Morgan, District of Columbia Public Service Commission

Peter Zschokke, National Grid

We are grateful for the many hours of discussion and advice provided by the many commission and utility staff who agreed to be interviewed for this project. We would also like to thank the Commissioners and staff representatives on the NARUC Energy Resources and Environment Committee and Miles Keogh of the NARUC staff, all of whom provided invaluable input and support.

The views and opinions expressed herein are those of the authors and do not necessarily represent those of any of the reviewers.

1. Introduction and Summary

1.1. Background and Purpose

Ensuring that reliable retail electric service is being provided at reasonable rates is more challenging than ever.

The providers of the generation component of that retail service, regardless of the presence or absence of retail competition, face a host of major uncertainties. These include high and volatile natural gas prices, uncertain wholesale power prices, uncertainty regarding the feasibility and economics of new generation capacity, and a wide range of possible environmental regulation futures, particularly with respect to greenhouse gas emissions. Providers must address those uncertainties when choosing supply strategies, resource mix, and ownership or contracting arrangements.

Regulators are faced with the difficult task of aligning resource plans and procurement strategies with the policy objectives of their particular jurisdiction. Those policy objectives may include enhancing reliability, managing risk, improving the performance of wholesale and retail markets and achieving reasonable rates. In other words, they must determine whether the proposed resource plans and procurement strategies represent “the best” choices from the full range of viable alternative plans and strategies, given their objectives.

Regulators face these challenges both in jurisdictions with retail competition and fully regulated states. Some states, such as Delaware, have recently enacted legislation mandating changes to procurement policies.¹ Others have grappled with these issues in various regulatory proceedings to institute new or updated procurement policies. Examples of recent relevant cases and proceedings in states with, or introducing, retail competition include:

- Illinois—Commerce Commission Docket 05-0159, Commonwealth Edison Auction, Dockets 05-0160, 0161 and 0162, Ameren Utilities
- Delaware—Executive Order No. 82

Examples of recent relevant cases and proceedings in vertically integrated states include:

- California—Rulemakings 01-10-024 and 04-04-003
- Oregon—Public Utility Commission Dockets UM-1056 and UM-1066 regarding IRP Policy
- Montana—Montana Administrative Rules, sub-chapter 20: Least Cost Planning—Electric Utilities. 38.5.2004

The parties to such proceedings must grapple with a number of questions at both a broad and detailed level. Broad questions that arise include:

¹ Electric Utility Retail Consumer Act of 2006, 75 Del. Laws ch. 242 (Apr. 6, 2006)

-
- What level of price volatility is tolerable for customers, taking into account the means at their disposal for managing that risk?
 - How can portfolio management help address public interest concerns regarding the level and stability of electricity prices?
 - Over what timeframe will the proposed strategy apply?
 - What level and stability of prices are expected to result during that time?
 - What are the key assumptions underlying those expectations?
 - How sensitive is the expected level and/or stability of prices to a change in those assumptions?
 - What flexibility is there to modify the strategy in response to changes in demand or supply conditions; at what points in time is that possible; and what is the process for doing so?
 - What alternative strategies were or should be considered, including energy efficiency, demand response, and renewable energy resources?
 - How do those alternative strategies compare in terms of level, stability, and sensitivity of prices to changes in assumptions?

More detailed questions can also arise, such as:

- What quantity of supply should be sought in each procurement and for what contract duration(s)?
- What portions of supply should be acquired through utility-owned generation, short-term purchases (e.g. day ahead markets), short- or long-term fixed price contracts, contracts for output from renewable energy resources, and investments in energy efficiency and demand side management (DSM)?
- When and how often should auctions, RFPs, or other procurements be held?
- How should auctions or procurements be designed to attract bids from providers of energy efficiency and renewable resources in addition to traditional supply side resources?
- Will the proposed strategy limit the ability to respond to carbon emission policies in the future?
- Will the proposed strategy limit the ability to respond to newly available resources, projects, or technologies in the future?
- Will the proposed strategy result in long-term commitments that have a high probability of exposing the provider or its customers to material stranded costs in the future?

The advantage to a portfolio management (PM) approach is that it provides regulators, utilities, and other parties with a systematic process and set of tools to answer such

questions in a transparent manner. Not only can PM reveal input data and assumptions, it can also identify and quantify the trade-offs between objectives under alternative strategies.

The primary purpose of this paper is to provide regulators with an overview of PM tools and practices that could be applied to the procurement of electricity resources to serve retail customers.² As will be seen, these tools and practices are valuable both in the resource planning of vertically integrated (or partially integrated) utilities and in the development and oversight of policies for default service in retail competition jurisdictions. The report only briefly reviews the benefits of PM, as a number of other reports have described the benefits of portfolio management in detail.³ The paper then explains how PM can be implemented in states that are fully regulated as well as in states with retail competition. Finally, it presents a discussion of several key technical aspects of applying PM, including modeling tools, analytical techniques, and necessary expertise.

1.2. What is Portfolio Management?

The term “portfolio management” has a long history in the realms of finance and investment. Under that name and others, the same risk management concepts and techniques have long been applied to procurement of commodities, including electric utility procurement of fuels and purchased power and local distribution company (LDC) procurement of natural gas.⁴ In recent years, the term has begun to be used in the electric industry to describe actual or suggested approaches to default service resource planning and procurement in states that have restructured their electric industry.⁵ However, application of portfolio management concepts need not be confined to retail choice states.

First, interest in development of a set of modern planning and procurement tools for application in the electric industry has been evolving over the last several years. In its 2003 resolution on PM, the National Association of Regulatory Utility Commissioners (NARUC) encouraged state regulatory commissions to

... explore portfolio management techniques that may be applicable to their particular circumstances, under either traditional or restructured markets, and to adopt appropriate regulatory policies to facilitate effective implementation of portfolio management practices by regulated utilities.

² Many electric utilities and load serving entities are familiar with these tools and practices, as noted earlier.

³ See, for example, Bruce Biewald, et al, *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers* Synapse Energy Economics, October, 2003. Prepared for the Regulatory Assistance Project and the Energy Foundation. Available at <http://www.synapse-energy.com/Downloads/SynapseReport.2003-10.RAP.Portfolio-Management.03-24.pdf>

⁴ Biewald, et al., and Frank C. Graves, et al., *Resource Planning and Procurement in Evolving Energy Markets*, The Brattle Group, prepared for The Edison Electric Institute, January 31, 2004.

⁵ In retail choice jurisdictions, various names are applied to this concept. Some of those are Basic Generation Service, Standard Offer Service, Provider of Last Resort service or POLR, and Basic Utility Service. Unless discussing the regime in a particular jurisdiction, we will use these terms interchangeably to mean the electric service provided to customers who do not shop.

In a 2004 report on resource planning and procurement in electricity markets sponsored by the Edison Electric Industry (EEI), the authors stated, “A synthesis is needed to meet customer needs for risk management and least-cost planning in the evolving industry structure that is a hybrid of competition and regulation.”⁶

Second, there is increasing interest in meeting future electricity requirements through a diverse mix of cost-effective resources, including energy efficiency, non-traditional renewable resources, and new technologies such as distributed generation, in addition to traditional supply side resources. For example, the Energy Policy Act of 2005 (EPAct) requires consideration of a fuel source diversity standard.⁷ Also, fuel diversity has been a major topic at both the 2005 and 2006 annual “Commissioners Only Summit” sponsored by National Regulatory Research Institute (NRRI). More recently, in July 2006, the President of NARUC and the Chair of EEI introduced a National Action Plan for Energy Efficiency that identifies energy efficiency as a high-priority energy resource.

This interest in applying a modern set of analytical tools to the acquisition of a diverse range of traditional and non-traditional resources is reflected in the following definition of PM, drawn from a 2006 report on clean energy policies and best practices prepared by the United States Environmental Protection Agency (EPA):

Portfolio management refers to energy resource planning that incorporates a variety of energy resources, including supply-side (e.g., traditional and renewable energy sources) and demand-side (e.g., energy efficiency) options. The term "portfolio management" has emerged in recent years to describe resource planning and procurement in states that have restructured their electric industry. However, the approach can also include the more traditional integrated resource planning (IRP) approaches applied to regulated, vertically integrated utilities.

Thus, portfolio management as applied in the electric industry may be seen as an approach to or refinement of traditional utility resource planning, which draws upon integrated resource planning, resource procurement, and risk management.⁸ As such, PM encompasses three distinct components:

- developing a resource plan,
- procuring the portfolio of resources identified in that plan, and
- managing that portfolio of resources on an ongoing basis.

⁶ Graves, p. 3.

⁷ EPAct 2005 Title XII Electricity, Subtitle E, Amendments to PURPA §1251(a).

⁸ Not all concepts, tools and practices from financial markets can be applied directly to electric markets; some may not apply while others may need to be customized. Conversely, many of the products and tools relevant to electricity portfolio management are unique to that industry.

1.3. How Might PM be Applied to Particular Retail Electricity Markets?

PM can be, and is being, applied in a variety of ways. In fact, the spectrum of approaches to implementing PM ranges from a narrow, passive approach at one end of the spectrum to a comprehensive, active approach at the other.

- A narrow, passive approach might be one in which planning considers only a short time frame and few resources, there is a single annual process for purchasing 100% of requirements, and periodic reviews and updates are absent.
- A comprehensive, active approach might be one in which resources are selected from a broad range of resources based on multi-year, long-term scenario analysis, and procured under a variety of ownership and contracting arrangements. Under a comprehensive approach, decision-making would reflect the cost and risk minimization benefits of diversification – diversity of fuels, diversity of technologies, including energy efficiency and renewables, diversity of contract terms and conditions (such as start dates and durations) and diversity of financial instruments for risk management. It would also include active or ongoing management of portfolio resources in response to changes in customer requirements and market conditions from day to day, week to week and month to month.

In any given state, the policy framework and objectives that govern the retail electric market, particularly electricity supply service, will be a key factor in the choice of a PM approach from this spectrum. For example, if the explicit policy objective of a state is to strongly encourage the development of a competitive retail market for all customers, the regulator may choose to support a narrow, passive PM approach for default service so that service will be relatively unattractive or provide maximum scope for retailers to differentiate themselves. On the other hand, if the explicit policy objective is reasonable rates to all customers receiving regulated retail service, the regulator may choose a comprehensive, active PM approach for default service. Similarly, a state's policy framework may assign responsibilities in certain ways, for example relying on an Independent System Operator (ISO) or Regional Transmission Operator (RTO) to ensure reliability. The application of PM must take such divisions of responsibility into account.

Given the variation in policy objectives among the states, it is not surprising that the retail competition states exhibit a range of approaches to portfolio management. Some states have essentially no PM. In other states a narrow, passive approach is being applied to the procurement and management of resources for default service. Appendix A presents key characteristics of default service procurement in the states that we surveyed. That approach typically consists of the following components:

- a procurement strategy using fixed-price, slice-of-load contracts of one or more term lengths up to three years, possibly overlapping in a laddered sequence,⁹

⁹ In some jurisdictions, slightly longer initial term lengths were used to synchronize procurement with ISO or RTO planning and commitment cycles.

-
- procurement via (usually) annual auctions or request for proposals (RFPs), and
 - absence of ongoing resource management between annual auctions.

There is little evidence of quantitative analysis of risks and benefits underlying the design of these procurement strategies. When contract laddering is the sole procurement tool used, it provides only limited portfolio management benefits, which are realizable only over only the length of that ladder, sometimes a very short time frame. Some states are beginning to address this limitation through new laws that explicitly try to obtain low costs over the long-term for their smaller default service customers. A variety of means have been adopted or are under discussion for this purpose. Maine, Delaware, and Maryland have each taken such steps. (See Appendix A of this report for details.) The general goal of the new policies is essentially to achieve reasonable and stable rates for default service. As a result, regulators in those states are beginning to explore ways to move to a more comprehensive, active approach.

The fully regulated states we surveyed had a comprehensive, active approach to portfolio management. Data from this survey is presented in Appendix B. In these states some form of long-term planning, which in some cases might be called "IRP," is required every few years. Procurement is not tied to an annual cycle of auctions, and ongoing management is expected. On the other hand, while planning in most of those jurisdictions included some analyses of uncertainty generally in the form of "sensitivity analyses," extensive quantitative analysis of the risks of various alternatives from a customer or public policy perspective was not the rule.

1.4. Key Conclusions

Our key conclusions are as follows:

- The providers of the generation component of retail electricity service face a host of major uncertainties, including future restrictions on emissions of carbon dioxide and future natural gas prices.
- Portfolio management, as applied to the provision of retail electric service, encompasses development of a resource plan, procurement of the portfolio of resources identified in that plan, and management of that portfolio of resources on an ongoing basis.
- Portfolio management provides regulators, utilities, and other parties with a systematic process and analytical tools for identifying a plan that will result in reliable service at reasonable rates. It offers transparency and tools for dealing with uncertainty and risk.
- Portfolio management can be applied to the generation component of retail service, regardless of the presence or absence of retail competition. Portfolio management approaches can be selected from a continuum ranging from comprehensive and active or narrow and passive.
- A narrow, passive approach to portfolio management may expose retail customers to rates that are higher or more volatile, than a comprehensive, active approach. A

strategy composed of a diverse mix of cost-effective resources, including energy efficiency and non-traditional renewable resources, may provide the best balance of expected cost and stable rates over the long-term.

- The policy framework and objectives that govern the retail electric market in a state influence the choice of an approach to PM in that state. Subject to policy constraints, regulators generally have authority to determine how portfolio management will be applied and by what entity.
- There is a range of computer models available for PM. They include planning models capable of addressing either (1) traditional cost-based engineering optimization analysis of the *expected* costs of *long-range* portfolios of traditional supply-side resources,¹⁰ (2) scenario-based comparisons of *long-range* portfolios of traditional resources for "robustness," or (3) short- to near-term quantitative risk analysis of a wide range of physical resources and financial instruments. Most quantitative risk analysis models are financial tools that analyze risk from the perspective of the supplier rather than retail customers.
- Most of these planning models require special effort in order to include energy efficiency and renewable energy in their evaluation of resources. In addition, these tools would benefit from improving their methodologies for analyzing long-term risks and comparing long-term decisions under uncertainty. For example, some existing optimization models require the representation of system operation to be simplified and limit the number of resources that can be considered in a model run. Such modeling constraints can prevent the long-term costs and benefits to consumers of a diverse mix of resources from being evaluated fully. Regulators may wish to promote research and development on improvements in these areas.
- Multiple modeling tools may be needed to address all three components of PM. However, integrating their results may be challenging.
- It appears that insufficient attention is being paid to development of tools for realistic analysis of long-term risks and long-term comparison of resource options that take uncertainty into account. Regulators may wish to promote research and development of open source algorithms or software in these areas.
- Staffing and resource limitations, as well as general lack of familiarity and acceptance, may be challenges to implementing or overseeing portfolio management at regulatory commissions. Regulators can do much to reduce such barriers over time.
- Portfolio management analysis and implementation will only be as good as the people who carry out and oversee those tasks. Managers and regulators need to consider the skills and abilities for doing so.

¹⁰ Models driven by optimization techniques may also lack fidelity in imperfect markets and situations where decision making and investment practices are suboptimal, as is often the case.

-
- It is not clear that the data necessary for portfolio management in the electric utility industry exist in all cases. Where it does exist, the data may be private and confidential. Certainly, some historical data series are publicly available, such as fossil fuel market prices and, more recently, electricity and weather hedge prices. Other data, such as load profiles and volatility, plant outage rates, and heat rates may be less available than in the past due to competitive pressures. Regulators and utilities can begin with data that is available, publicly or under confidentiality arrangements. They also may wish to identify new information that should be developed to maximize the feasibility and usefulness of risk analysis.
 - The application of certain elements of portfolio management in the electric industry is still relatively new. Some fully regulated states and some retail choice states have begun to take action, but there is much room for improvement and certainly room for more states to implement PM. Regulators can play an important role in encouraging further improvements in, and adoption of, these concepts. Regulators may wish to promote the development of portfolio management tools that can address energy efficiency and renewable energy resources to the same degree as traditional supply-side resources at every stage of the process.
 - Screening out or winnowing down major diversification options very early in a planning study or risk assessment can seriously compromise the results. The real value of those options may not become apparent until much later in those studies or assessments, when analyses of risk and uncertainty are prepared.
 - Regulators will likely need to exercise considerably more oversight of risk mitigation, in the future. Unfortunately, clear methods for conceptualizing risk in utility portfolio management are not well developed. Regulators may wish to consider exploratory proceedings to develop and communicate risk management and portfolio management goals and criteria.

2. Portfolio Management: Objectives and Applications

Portfolio management is a process and a set of tools that can be applied in order to achieve objectives specified by the user. It needs to be informed with the goals and values regulators want pursued.

This section presents a brief overview of the public policy objectives that regulators may seek to achieve through the application of portfolio management, as well as the manner in which portfolio management can be applied under various market structures.

2.1. Portfolio Management Can Be Used to Achieve Public Policy Objectives in a Transparent Manner

The broad public policy objective that regulators traditionally sought to achieve with respect to retail electricity markets was reliable service at reasonable rates. This policy objective was typically set out explicitly, either in legislation or regulations. Some states changed these broad objectives when they implemented retail competition. More recently, some states with retail competition have passed new legislation effectively requiring default service to be provided at reasonable rates. For the purposes of this report we will focus on the objectives of reliable service at reasonable rates.

Reliable service at reasonable rates is not a new objective. Regulators have a long history of reviewing utility plans and operations to determine if they satisfy that objective. Out of that history many states have developed explicit, quantitative benchmarks for certain aspects of reliable service against which regulators can assess utility plans and operations. One such benchmark is a loss of load probability (LOLP) of one day in ten years for generating capacity adequacy.

In contrast, there are no generally accepted quantitative benchmarks for “reasonable rates.” Instead, the criteria for reasonable rates vary. This variation is driven by many factors such as differences in the availability of resources and differences in regulatory policy tradeoffs. Regulators consider a number of facts and objectives when making energy policy decisions and in determining whether rates are reasonable. Those facts and objectives vary from state to state, as do the weights that regulators apply to them.

Facts and objectives that regulators in most states consider when assessing whether retail electric service rates are, or will be, reasonable include:

- The resource options commercially available,
- The costs of those resource options,
- Whether the proposed mix of resource options minimizes costs to ratepayers (i.e., minimum rates and bills), and
- Whether the proposed mix of resource options will result in stable costs to ratepayers (i.e., stable rates and bills).

Regulators may also consider fuel diversity targets, renewable energy targets, carbon dioxide targets, other environmental goals, service to low-income customers, impacts on the local economy, and flexibility to respond to major changes in market conditions and public policies over time.

The desire to achieve multiple objectives often complicates the determination of whether rates are reasonable, because the objectives are often conflicting. For example, one strategy might be to minimize costs for the year by purchasing all generation supplies from a spot (e.g., day ahead) wholesale market. This strategy might be premised upon a belief that a strategy that included any multi-month contracts at fixed prices would incur extra risk premium costs on average in the long run. On the other hand, this hypothetical purchasing strategy could result in very volatile costs that would necessitate some sort of routine rate true-up mechanism, and, as a result, lead to highly volatile rates for customers. A second, alternative strategy might be to stabilize rates by acquiring all supplies via long-term fixed price bilateral contracts, say through a single procurement for 100% of requirements. This alternative hypothetical strategy stabilizes rates and simplifies administration, but could result in higher expected costs than the first strategy on average over time if, for example, sellers of fixed price contracts wish to and can obtain a risk premium in return for that price certainty. Neither hypothetical strategy would satisfy both objectives of minimum costs and stable costs. In contrast, a third hypothetical strategy consisting of a mix of spot purchases and fixed price contracts might partially satisfy both objectives in a balanced manner, trading off somewhat higher costs in exchange for somewhat more stable costs, and vice versa (again, assuming that fixed price term contracts require payment of a risk premium).

One major way in which states differ is the timeframe or planning horizon over which they assess the reasonableness of the rate impacts of resource decisions. In some states regulators assess reasonableness over a short-term time frame, one to three years for example. In others regulators consider the implications of the strategy and resource mix underlying the rates over the long-term of five to twenty years, as well as assess the resulting rates expected over the short-term.

Portfolio management provides regulators, utilities, and other parties to these determinations with a process, and set of tools, to select a strategy that will result in reliable service at reasonable rates and to do so in a transparent manner. Not only can it reveal input data and assumptions, it can also identify and quantify the trade-offs between objectives under alternative strategies. That transparency can, in turn, assist regulators in determining the weight to apply to each objective.

2.2. Portfolio Management Can Be Applied under Any Market Structure and Regulatory Framework

The market structures and regulatory frameworks governing electricity supply service to retail customers vary from state to state. For the purposes of this report, those structures can be grouped under one of two broad frameworks – fully regulated or retail competition. For simplicity, this discussion will consider the retail competition framework to be a fully developed one where the provider of default service (usually the distribution company) is not allowed to retain a generation or merchant power function.

One can characterize and distinguish between those two frameworks according to the entity responsible for providing generation service and the entity responsible for ensuring that those rates are reasonable. The distinctions between the two market structures according to those attributes are summarized in Table 2.1, below.

Table 2.1 Key Attributes of Alternative Retail Market Structures		
Market Structure/ Attributes	Fully Regulated	Retail Competition with no Merchant Function
Retail competition	Not Allowed	Allowed
Responsibility for providing generation service	Utility	Competitive market for customers who shop <i>Default service¹¹ for customers who do not shop</i>
Responsibility for monitoring and oversight to ensure that generation service is reliable and reasonably priced	Regulator	Regulator

Portfolio management tools and practices can be applied to the resource decisions that need to be made under either of these frameworks.

2.2.1. Application of Portfolio Management in Fully Regulated Markets

In states with a fully regulated framework, utilities employ some form of portfolio management to select and procure the appropriate resources, implicitly or explicitly. Examples from the states that we surveyed are presented in Appendix B. In these states, portfolio management is usually intertwined with resource planning procedures, such as least cost planning or integrated resource planning, where they exist. Portfolio management may also be a part of the fuel procurement practices for generation-owning utilities.

The specific procedures through which portfolio management is applied vary from state to state. However, the general approach through which the three basic steps in portfolio management are applied are summarized below.

1) Preparation and periodic updates of resource plans

Utilities are required to file a resource plan at least every two to three years. The plans cover a long-term horizon, typically at least ten years. They begin with a projection of customer electricity requirements over that period and then evaluate all options available to meet those projected requirements, including supply-side resources, transmission and distribution investments, demand-side resources and purchased power. In some cases, resource planning may encompass fuel contracting for utility-owned generators, as well as plans or policies governing

¹¹ Also known as Standard Offer Service (SOS), basic generation service (BGS), and Provider of Last Resort service (POLR)

off-system sales of power or disposal of power supply assets. That evaluation considers the reliability, economics and risk attributes of those resource options and may also address their financial, environmental and social attributes. Based upon that analysis the plan identifies a specific mix of resources and/or strategy that the utility believes will result in reliable service at reasonable rates.

Regulators review these filings. In some states, they issue an acknowledgement that the plan satisfies the filing requirements. In other states, the regulator may approve the filing, an act that *may or may not* effectively pre-approve any major new initiatives proposed in the plan, such as construction of new capacity or execution of a new long-term purchased power agreement, depending on that state's laws and practice.

2) Procurement

Utilities execute planned procurements by acquiring assets in the form of capacity and fuel, and then using those assets to meet the requirements of their customers. They do this through periodic investments in generation capacity of their own, routine purchases of fuel, or execution of fuel contracts or hedges for that generation and periodic execution of power purchase agreements. In some cases, wholesale sales of power or hedges, or disposal of power supply assets may be part of this execution phase.

Regulators review the reasonableness of the costs and revenues resulting from these utility decisions. Typically those reviews occur when the utility applies for a change in its base rates. In addition, in states which allow utilities to adjust their base rates for changes in fuel and purchased power costs, those reviews may also occur annually in “fuel adjustment proceedings.”

3) Ongoing management

By ongoing management, we mean the as-needed adjustment of plans and resulting procurement actions reacting to changes in the load requirements and market conditions. As load requirements and market conditions change, the utilities modify their use of owned generation and purchased power assets accordingly. They may increase or decrease off-system sales from capacity that is temporarily not required to serve native load, acquire new supplies, ramp up or down demand-side management programs, or take a variety of other actions.

Regulators review the reasonableness of the costs resulting from these utility decisions in the same forums as the procurement decisions.

2.2.2. Applying PM in Retail Competition Markets

Portfolio management is applicable to the procurement of resources for default generation service in states with retail competition. However, as noted earlier, any decision regarding the scope and nature of portfolio management to be applied to this service is primarily a policy issue. This decision will necessarily flow from the policy framework and objectives that govern the retail electric market in the state.

This policy issue has been the subject of debate since the onset of retail competition. When retail competition was first introduced default service was expected to be either a temporary service during the transition to full competition or a true “default” service that relatively few customers would take, and then only while they were between competitive suppliers. Based upon that expectation, some regulators felt that a basic strategy and an annual procurement would be appropriate for the acquisition of supplies for default service.

Contrary to those initial expectations, most of these states have seen almost all residential customers as well as many small commercial, institutional, and industrial customers remain on default service. Given the number of customers who continue to rely on this service, and the recent sharp increases in the rates for that service resulting from the current acquisition approaches, regulators are now faced with the question of whether to require the use of a more complete and sophisticated portfolio management approach for the acquisition of power needed for default service.

If a regulator in a retail competition state is interested in such an approach, an important first step will likely be a review of the existing legislation, regulations, and orders governing that service. For example, changes may be required in order to assign responsibility for:

- more comprehensive resource planning, in terms of both time frame and a wider range of resources (e.g., energy efficiency, renewable resources);
- more latitude in procurement, including more flexibility in the timing of procurements, the quantities procured and contract duration;
- changes in procurement to encourage bids from providers of energy efficiency and renewable resources; and
- periodic analyses and updates of the acquisition strategy.

These responsibilities can be assigned to the incumbent distribution utilities or to a third party, but what is essential is that the responsibility be assigned to *someone*.

2.3. Portfolio Management Provides a Process and Set of Tools for Examining Complex Resource Planning and Procurement Issues

Resource planning and procurement have become increasingly complex over the past 20 years. Regulators need methods and tools that can be used to determine whether a particular resource plan will result in reliable service at reasonable rates.

To illustrate this challenge, consider each of the major steps involved in developing a resource plan and procuring the necessary resources.

The first step is to choose a planning horizon. Use of a reasonably long-term horizon, e.g., 20 years or more, allows a range of resources and costs to be considered, including new renewable resources that have yet to be built and anticipated carbon dioxide emission regulations. The next step is to forecast the quantity of capacity and generation

required. These requirements can be forecast, but are obviously subject to uncertainty. In addition, the quantities that will be required from hour to hour and day to day are very difficult to forecast because they are so sensitive to weather and economic conditions. In retail competition markets there is additional uncertainty as to what quantity of load will switch to, or from, competitive suppliers.

The third step is to identify the viable resources and associated contracting and hedging options. These may include:

- Demand side management and energy efficiency
- Distributed generation
- Supply side resources (subject to resource availability)
 - Hydro
 - Wind
 - Solar
 - Gas-fired
 - Coal-fired
 - Nuclear
- Physical contracts
 - Spot
 - Term contract
- Financial instruments

The key attributes of each resource need to be projected for the planning horizon, including the quantities available at various points in time and their corresponding costs and volatility.

The fourth step is to then identify the alternative portfolios or strategies, consisting of different mixes of these resource options that could be used to provide reliable service at reasonable rates. This may entail evaluating hundreds of possible candidate plans or portfolios in light of the many potential permutations and combinations of these resources.

This evaluation and selection problem can, in many instances, be solved mathematically using computers by formulating it as an “optimization” problem. Under this approach the computer software is told to find the optimal mix of resources that will minimize risk while minimizing expected cost.¹² As one would expect, there are data and computational limits to solving this problem. For example, the assumptions for volatility and uncertainty in key inputs are notoriously difficult to characterize. Computationally, the vast number of possible resource combinations and timing of those mixes requires simplifying assumptions (such as trimming the available resource options down to a small handful of “typical generating unit types”) to enable the models to run in a reasonable amount of time. Portfolio management provides regulators, utilities, and other parties with a process and set of tools to analyze these complex resource planning and procurement issues. As

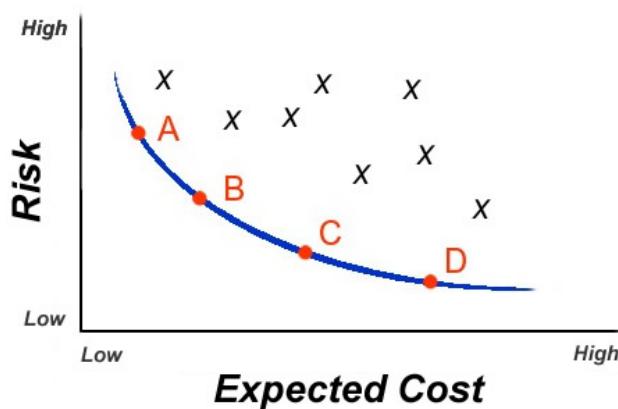
¹² This would generally be a nonlinear optimization model, likely a dynamic, multi-period one.

noted earlier, this approach can help all parties identify the assumptions to which the results are most sensitive and can also identify and quantify the trade-offs between objectives under alternative strategies. That transparency can, in turn, assist in determining the weight to apply to each objective.

Choosing Among Portfolios with Different Costs and Risks

Once candidate portfolios have been identified, their expected costs and variability can be estimated. The figure below can begin to give a sense of how candidate portfolios compare.

Example of Resource Plan Trade-off Curve



Each portfolio is represented by a symbol on the graph. The vertical axis indicates the portfolio's risk/uncertainty and the horizontal axis its expected cost. For a given expected cost, there will be one portfolio with the lowest level of risk, and vice versa. In our illustrative figure, A, B, C, and D mark four portfolios, each of which is the one that is least risky for a particular expected cost. As you move down along the curve connecting those four cases from right to left, there is a trade off in higher expected cost in exchange for less risk, i.e., more stable costs. One would always prefer a portfolio located somewhere along that line, because those portfolios represent the optimal levels of expected cost and risk.

The line connecting these "optimal" portfolios is the tradeoff curve, sometimes called the "efficient frontier." Considering only these two factors (expected cost and some particular measure of uncertainty), there is no economic reason to choose a portfolio above that frontier. However, each portfolio will have many non-economic pros and cons and there are various risk measures to consider, so the choice is never that simple. And, even along the frontier, the choice of a specific portfolio on that line will depend on what the decision-maker considers to be an acceptable tradeoff between the two objectives.

3. Confronting Uncertainty and Risk

This section will consider certain key issues regarding organization and implementation of portfolio management for regulators. The first subsection discusses why and how portfolio management applies in both fully regulated and retail choice jurisdictions. The next subsection addresses questions of organization and readiness for portfolio management approach to risk management. The third subsection highlights the challenge of making and communicating choices about risk management. The last subsection discusses in detail ways to measure and compare the risk of resource options and portfolios.

3.1. Two Contexts for Portfolio Management

As explained in Section 1 of this report, regulators from states with retail competition as well as from states with fully regulated utilities may need to address portfolio management.

Portfolio management has emerged in states that have restructured their electric utilities as an approach for acquiring resources to provide default service. In these states regulators and utilities responsible for implementing and overseeing default service procurement are faced with markets that do not always deliver stable, reasonably priced power in response to simple competitive procurements. Several states are moving towards a long-term view for delivering default service in the public interest.

In states with fully regulated generation service, vertically integrated utilities weigh various utility-owned resource options including new generation, transmission expansion, and DSM programs as well as power purchase contracts. Fully regulated utilities and their regulators now need to enhance resource planning, such as IRP, with more and better analysis and increased consideration of uncertainty and risk. Given the complexity of current markets and market products, traditional scenario analysis will no longer suffice to guide decision-making.

A sampling of some of the major new uncertainties facing regulators and utilities in all of these states help illustrate the complexity of their planning and procurement problems:¹³

- Will RTOs continue to develop?
- How will politics, pressure from the insurance industry, and fuel prices affect climate change regulation? How will "early credit" programs be treated?
- Will transmission companies proliferate and will they be able to generate enough return to gain access to capital for expansion?
- Will consumer interest in "clean power" increase or wane?
- Will the United States continue to be bifurcated into regional markets and territorial markets?

¹³ Adapted from http://www.scottmadden.com/pdfs/ScottMaddenEIUFall04_Full.pdf

-
- Will wholesale market power issues cause divestitures, just mitigation activity, or continue to erode competitive pressures?
 - Will capacity expansion be driven regionally and, if so, by what mechanisms?
 - Will renewables development satisfy state targets?
 - Will fuel prices and environmental constraints strand some assets and speed development of new technologies?

Uncertainty and risk are addressed in the context of IRP as well as in financial risk management. Each of those perspectives emphasize detailed, quantitative analysis. IRP practice tends to emphasize refinement of long term expected or most likely cost and performance data for options. This is often supplemented with an engineering type bounding analysis, although in practice such bounding analyses often amount to simply running "plus or minus X%" scenarios or scenarios based on the range of estimates from different experts or studies. In contrast, quantitative analysis of the relative likelihood of various deviations or of how different risks interact to amplify or offset each other are relatively rare. Financial assessments of investment portfolios, on the other hand, currently emphasize detailed modeling the effects of variability and interactions of so-called "stable processes" by considering random variations in performance based on historical data for established products, but rarely consider longer term resource choices.

Given the strengths and weaknesses of the analytical tools and practices of each approach, and the planning and procurement problems in today's markets, we expect to see a gradual convergence of the portfolio management practices for IRP-like jurisdictions and default service procurement jurisdictions. In Section 4 of this report, we show that the current divide between the two approaches is mirrored in the software options available, too. Regulators may wish to push for a synthesis of these approaches, encouraging both rigorous detailed analysis and an understanding of the long range situation. New research and development may be necessary to accomplish this.

A portfolio management approach can also deliver side benefits to all consumers, even those who choose to shop from competitive suppliers. For example, inclusion of long term or even life-of-unit purchases from new renewable generators (or new generators not fueled by natural gas) can not only stabilize the cost of power for default service, but also lower clearing prices for all consumers by promoting new generation construction and reducing price pressure on natural gas at times of peak demand. A portfolio management approach to meeting the power needs of default service is compatible with the development of a vibrant competitive generation industry. In fact, by providing stable long term markets, a portfolio management approach for default service can enhance the health of the currently distressed generation industry by alleviating its dependence on an unfriendly project financing market.

3.2. Integrating IRP and PM Concepts

Portfolio management and integrated resource planning are not irreconcilable concepts. Rather, they are labels that emphasize different aspects of resource planning, all of which should be included in an ideal resource planning process.

Integrated resource planning involves the development of a portfolio of existing and new resources of all types that help achieve the lowest cost for consumers over the life of the plan. Each time an IRP is updated, an essentially new IRP is created, treating resources acquired since the previous update as committed and seeking the best selection of additions to form its new plan. Risks are usually assessed qualitatively or via scenario analysis, trying to find the resource plan that best combines a low cost with a reasonable degree of robustness against uncertainties. While IRPs can include fixed term purchased power contracts or consider disposing of committed resources, the emphasis is usually on permanent acquisition of resources.

On the other hand, portfolio management emphasizes assembling and managing a collection of resources, often entirely fixed-term purchase contracts. Diversification of expiration dates, vendors and, sometimes, term lengths is a typical tool in PM. Carefully designed competitive procurements are often the centerpiece of a PM approach, especially when over the counter markets are not fully developed.

PM has been applied in a narrow, passive manner in some states with retail choice and default service programs. For example, New Jersey, Maryland and Delaware limited procurement for default service generation to laddered two or three year, slice of load contracts obtained via a once-a-year auction or RFP. While such selections are implicit resource plans, they arbitrarily exclude a wide array of viable resources and limit the degree of risk mitigation provided to retail consumers. Conversely, preparing an IRP in which the focus is on identification of the least cost mix of permanent generation acquisitions and there is no assessment of risk would also represent a very limited approach to portfolio management—one with few choice points, limited diversification, and few market force effects.

Clearly, IRP can be improved by harnessing competition, by comparing resource plans using quantitative measures of risk in addition to expected cost, and by subjecting portfolios to active management. Conversely, procurement for default service (or other needs) can be improved by embracing a broad range of resource alternatives, striving for least cost service over time, and focusing on the risks borne by consumers rather than only those borne by the utility.

Applying aspects of portfolio management to the development and implementation of IRPs should be viewed as a challenging but natural enhancement of IRP for vertically integrated utilities. Several states have begun to consider such a move, especially with regard to risk management.

The descriptions of IRP and PM given above are generalizations based on typical practice among the states and may not be implemented identically in every jurisdiction. In fact, various practices can be called IRP or PM and may include some beneficial features of IRP or PM, but not fully realize either concept, much less an integration of the two. In principle, they are two ways of looking at the same problem. Ideally, resources would be planned, procured, and managed in ways that are both “integrated” and reflect “portfolio management.”

3.3. Organizational Issues

Organizational readiness and commitment are seen as critical to successful implementation of risk analysis and risk control through portfolio management.

While no one person at a major utility can (or should) make all decisions regarding portfolio management, it is the chief executive officer (CEO) who ultimately bears this responsibility. The CEO can best achieve portfolio management success by dividing up portfolio management responsibilities amongst the following types of employees: chief financial officer, chief risk officer, internal auditor, accountants (internal and/or external), chief technology officer, and others. In addition, the board of directors plays a key role in helping to define the overall risk tolerance of the organization.

It is interesting to note that, under Sarbanes–Oxley compliance requirements, the CEO is now legally responsible for ensuring that company-related risks are reported to shareholders. Not only is the CEO responsible legally, but from a practical standpoint the CEO plays a critical role in terms of setting the tone for policy implementation throughout the organization. Unless he/she makes portfolio management a key priority for the organization, it will likely be unsuccessful.

Direction and motivation are critical to success in risk management and planning for risk management. The tone for any new direction is usually set by the leadership at the top of the organization. Thus the application of these new tools in the electric industry will benefit if regulators set out clear expectations and if utility management commit to portfolio and risk management.¹⁴

With regard to PM implementation, organizations have options. A utility could choose:

- a narrow approach focused on specific resource planning activities mandated by law or regulation,
- a broad approach focused on risk analysis and management in all aspects of the firm, or
- an "optimally scoped" approach that seeks to strengthen portfolio and risk management in targeted activities, improve processes for that purpose, and establish ongoing monitoring and improvement.

Recently, under the impetus of Sarbanes-Oxley mandates, many firms have considered how best to organize risk assessment and risk control. A number of questions about a firm's readiness for risk assessment and control should be addressed. Some of these are:

- How well has the organization implemented other change efforts?
- Is the executive management supporting the effort, visibly and effectively enough to get buy-in from the entire organization?
- How well does executive management understand the effort required to implement PM and management's role in that implementation?

¹⁴ The following material draws on Anne Marchetti, *Beyond Sarbanes-Oxley Compliance: Effective Enterprise Risk Management*, John Wiley & Sons, 2005.

-
- Is the organization committed to providing resources (people, time, money) to both the design and implementation of the effort?

Regulators seeking to implement portfolio management and risk assessment at Commissions and utilities should ensure:

- clearly articulated reasons for implementation;
- a clear connection to the strategy of the organization;
- full implementation;
- integration with existing processes and initiatives;
- active, visible leadership;
- commitment of adequate time and resources;
- timely and thorough communication among regulators, advocates, utilities and other stakeholders, as well as throughout the affected portions of the utilities, including feedback and reinforcement;
- routine progress and performance measurement and review of corrective actions; and
- skilled, trained employees at commissions and utilities.

3.4. Making and Communicating Choices about Risk Management

Perhaps the first concept that comes up in a discussion of portfolio management is "diversification." We have devoted considerable discussion to that topic here and elsewhere.¹⁵ A second major concept that comes up in such a discussion is "risk tolerance." Risk tolerance refers to one's willingness to accept the risk of an undesirable outcome when making an investment choice.

It is natural, even traditional, for portfolio planning to determine, and take into consideration, the risk tolerance of an investment portfolio "owner" at an early stage in the process. A much more difficult problem arises in the context of applying PM to an electric utility, where the utility may be the "owner" but the costs will be paid by a large group of customers. It is difficult to express or ascertain the risk tolerance of individual customers in a meaningful way, much less whole classes of customers. While this report does not present a recipe for regulators to use in establishing the level of risk appropriate for the resource portfolio of a fully regulated utility or for a default service provider, this section attempts to clarify the issues that should be considered.

Decisions about risk should not be made in a vacuum or on a hunch. Even the sort of on-line questionnaire designed to guide personal investing decisions takes into consideration objective aspects of the investor's current situation and plans for the future. Risk tolerance discussions for individuals are driven by such life situation factors as age,

¹⁵ Biewald, et al. *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low Cost, and Efficient Electricity Services to All Retail Customers*. Synapse Energy Economics, 2003. Available at <http://www.synapse-energy.com/Downloads/SynapseReport.2003-10.RAP.Portfolio-Management.03-24.pdf>

dependents, taxable income and projections thereof, existing assets and liabilities, commitments, fixed expenses, health status, retirement and other plans, and so on.

Regulators have been making risk tolerance judgments on behalf of ratepayers as long as they have been setting rates. Every decision to approve construction or a long term contract accepts certain risks and avoids others. Traditionally, such decisions have been made after careful qualitative and, sometimes, partially quantified consideration of the risks and uncertainties of a project under consideration and (slightly less often) the risks and uncertainties of the alternatives. However, trying to discipline or even quantify those tolerances is unbroken ground for many utilities. In fact, such discussions are typically based on evidence that amounts to the opinions of persons with a stake in the matter. An EEI report expresses the opinion that "The 'right' amount of risk-bearing for customers (in rates) is not self-evident."¹⁶ Moreover, we should not expect this job to be easy. In fact, that study calls on regulators to either specify the risk tolerance to be used or provide guidance to utilities on how it should be measured.

A finance expert might approach this question by asking regulators to name their risk tolerance (presumably something numerical, like "the probability that rates will increase by more than X% in any one year or more than Y% over five years should be less than Z%") and suggest that it would then be straightforward to determine how to deliver that level of certainty and offer to tell regulators what buying that degree of certainty will cost as of a given market day. Perhaps that could be done in theory, but there is no simple answer to the question of risk tolerance of customers. In part, this is because customers are not a homogeneous group and in part because the answer will depend on the methods used for reducing risk and their side effects.

Some would argue that rate stability is not free and all hedging comes with a cost. Others argue that long term hedges simply are not available. However, failing to hedge huge market exposure has external costs, while the absence of long-term, market-based forwards (only one of many ways to hedge risk) may be something of a self-fulfilling prophecy. Shipping companies could buy cargo and hull insurance for hundreds of years before anyone bothered to sell life insurance, but practically as soon as it was offered, life insurance was a huge success. Thus, markets for long term power contracts or other hedges may well develop if there is an adequate demand for them by buyers and sellers.

How and when the risk/cost tradeoff analysis is performed during resource planning and/or procurement processes can be just as critical to sound portfolio management as the metrics used and the preferences applied, especially when assessing longer term resources and risks. For example, as a recent national laboratory study observed,

[utility] resource plans vary considerably in how they define expected risk, and how they balance the expected cost and risk of different candidate portfolios. In selecting a 'preferred' portfolio, a utility would ideally review consumer preferences for cost-risk tradeoffs, and select the candidate portfolio that fits most closely with the risk preferences of the majority of its customers. This approach, however, is rarely used. Instead, in all of the cases we reviewed, the cost-risk

¹⁶ Graves, 2004, p. 21.

tradeoff (if made) is based on the subjective judgment of each utility, informed by any counsel provided by the utility's regulators or external stakeholders.... In other words, the cost/risk tradeoff has often been made – in part based on consideration of fuel price risk – before carbon risk is considered, in which case carbon risk is sometimes relegated to helping to distinguish between a few finalist portfolios.... As a result, some of the “renewables” portfolios in our IRP sample exhibit as much or more exposure to natural gas price risk than other portfolios.... By the time carbon risk is assessed, some renewables portfolios – i.e., those best able to mitigate carbon risk – may have already been weeded out of the process, potentially leaving the model to choose from among a number of sub-optimal portfolios.¹⁷

That study recommends "a more holistic assessment of risk, and approach to the cost/risk tradeoff" rather than a "sequential, winnowing approach." It goes on to point out that

...scenario analysis, and the risks analyzed with that technique, may end up as a mere sideshow to stochastic analysis. Related, a large and varied set of candidate portfolios should be evaluated for their ability to mitigate risks; otherwise, analysis results may be unduly affected by the pre-selection of possible candidate portfolios.

In summary, regulators will likely need to oversee or manage risk mitigation, but clear methods for conceptualizing risk in utility portfolio management are not well developed. Regulators may find it useful to consider exploratory proceedings or alternative input methods, such as deliberative polling, but in the end, regulators will need to develop and communicate risk management and portfolio management goals and criteria to generation service providers, either proactively or in response to utilities' implicit or explicit risk management choices. Further research on this point may be of value and could begin with a systematic effort to review the techniques used by institutional investors and manufacturers dependent on long lead time commodities, followed by analysis of how their methods may or may not be useful in utility planning and its oversight.

3.5. Techniques for Analyzing Risk Exposure and Uncertainty

3.5.1. Measuring Risk and Expected Benefit

Risk and uncertainty are inherent in all enterprises. But risk needs to be balanced against expected benefit. The balancing of risk and expected benefit in utility regulation differs from the balancing that occurs in business or investing. However many of the tools and metrics for measuring risk and expected benefit in business and investing can be, and have been, applied to the electric industry.

¹⁷ Ryan Wiser and Mark Bolinger, "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans," *The Electricity Journal*, Feb. 2006; Ryan Wiser and Mark Bolinger, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, Lawrence Berkeley National Laboratory, 2005. Available at <http://eetd.lbl.gov/ea/ems/reports/58450-journal.pdf>

Business managers and investors decide how much of a return they require on a prospective investment in exchange for taking on a given level of associated risk. They then make go/no-go decisions on individual projects by measuring, implicitly or explicitly, the risk of a given project and its expected return to see if those criteria meet their investment threshold. Bond ratings are a tool commonly used for this purpose by investors. For example, an investor may choose not to invest in highly-rated corporate bonds unless the bonds bear an interest rate of, say, 3% above the interest rate for U.S. government bonds, because even highly rated firms may fail.¹⁸ The same investor might be willing to invest in the same corporation's common stock only if the expected return is 10% above the interest rate for U.S. government bonds, because common stock is the first type of security to suffer (i.e., to miss dividend payments or lose market value) when a firm is in financial trouble.

Rather than comparing expected return to perceived risk, utility regulators typically want to minimize rates or cost of service or both, while taking into account the degree of risk that ratepayers will face, as well as the risks to investors. Thus there is a need to balance the expected cost of a resource, or a portfolio of resources, with the risk that the actual cost of the resource may be more or less than expected at various times over the planning horizon, thereby introducing volatility into the cost of service during that period. It is also important to consider the risk that a resource choice will fail to provide necessary power (or save power in the case of DSM resources), triggering a need to buy at market rates. Finally one must consider how a given resource plan will impact the ability of the utility to attract capital. While the kinds of benefits and risks that regulators evaluate and balance are not exactly the same as those that businesses and investors consider, many of the tools and metrics available are suitable or may be adapted to either.

It is conceptually simple, but sometimes technically difficult, to compare different portfolios of resources based on their expected costs. Present value life cycle cost is the usual measure employed for that purpose. Unfortunately, there is currently no single, generally agreed upon measure of the risk of a resource portfolio. The accompanying text box on "Random Variables and Portfolio Management" explains portfolio risk in terms of cost uncertainty and the basic concept of comparing the riskiness of two portfolios. Appendix D of this report describes a variety of portfolio risk measures. The rest of this subsection explains a few of those risk measures and presents some key ideas about risk measurement.

¹⁸ U.S. government securities are often used as a proxy for an investment that bears no risk except for the risk that the inflation rate may change.

Random Variables and Portfolio Management

What is a random variable? A *random variable* is a number whose value changes, say over time, in a way that cannot be predicted in advance. Planning risk for utilities is often a result of the random variability of weather, inflation, economic growth, power plant availability, the market price of gas and the like. These and similar factors have a big influence on the cost of a portfolio, but forecasts and trends of them are subject to unpredictable fluctuations. Often we are most interested in the long term average cost of a portfolio of resources; that cost, itself, is usually a random variable because it is determined by interaction of the random variables just mentioned and others, too.

What is a probability distribution? We usually know *something* about the behavior of a variable, even if it is random. The high temperature in Chicago on July 4 next year maybe impossible to predict, but we have lots of data about past temperatures. Using that data, we can say with some confidence that the most likely value is the long term average for that place on that day of the year. Using that data, we can also find the *probability* that the temperature will 90° or 101° or any other particular value. If we draw a graph showing temperature values on the horizontal axis and their probability of occurring as the vertical axis, we have a picture of that variable's *probability distribution*. (The figure below shows two examples.) In many cases, the graph may look like a bell curve; for others, it may not. If a variable can have only a few different values, such as yes or no or 0% to 100%, the graph will be a bar chart with one bar for each possible value.

What is an expected value? For a random variable, the *expected value* is the value we expect to see *on average* over time, but not necessarily the single most common value.

How is variability measured? Appendix C to this report describes a number of ways to put a number on the uncertainty of a portfolio's cost, but they are all ways of expressing the width of the probability distribution.

Where do we get probability distributions for resource planning variables? If historical data exists, such as for weather or fuel market prices, we can rely on that data *if* we are confident that the systems that produced those data will not change. For example, we might believe that a manufacturer's historical data on the availability of the generators of a certain type will be representative of the units we need to model. On the other hand, we may feel that weather data need to be adjusted for the impact of climate change. Finding good data for the probability distributions of resource planning variables is challenging, especially for long-term planning.

How do probability distributions relate to portfolio management? The riskiness of a portfolio of resources is related to the variability or uncertainty of its cost. For example, a portfolio consisting of only two resources, a single generating plant and spot market purchases, would have at least four sources of uncertainty. One is the uncertainty in the plant's fuel cost. Another is the variability in the market price paid for any extra power needed or earned for an excess sold. The third would be variation in the load to be served, because that determines how much power is available to sell on the market or how much extra needs to be bought. Lastly, the availability of the plant helps determine how much market power needs to be bought or sold. If we know (or can assume) the probability distribution of those four variables, we can compute the probability distribution of the portfolio's projected cost. The probability distribution of the cost for this hypothetical portfolio might look like Curve A in the figure in this text box.

How are probability distributions used in comparing portfolios? Suppose we wanted a portfolio with a more stable cost. Then we might consider adding a fixed price purchase contract to cover some of the excess power need. This would reduce variability as some or all of the purchases would be at a known price. We might also purchase options for the generator's fuel. The options would cost us a certain amount whether we exercise them or not, but would ensure that the fuel price does not exceed a certain value and also reduce the variability of the portfolio's cost. We could use this new information to compute the probability distribution of the revised portfolio's projected cost. The distribution of the cost for this revised portfolio might look like Curve B in the figure below.

Curve B is much narrower, illustrating the reduction in uncertainty about portfolio cost, but is shifted to the right, reflecting the extra fixed cost of some of the risk mitigation measures. So, comparing these hypothetical probability distributions, we would have to make what may, or may not, be a difficult decision, i.e., is it worth paying a somewhat higher expected cost to avoid exposure to the possibility of a very high cost. If the differences in costs under the two approaches are minimal the decision may not be difficult. If the differences in costs are large, the decision becomes more difficult. Or, we might decide to look harder for cost effective ways to reduce risk, such as adding less volatile renewable generators or ramping up energy efficiency to reduce the need for market purchases.



Figure 3.1. One view of the possible impact of hedging on risk exposure for the cost of a portfolio of resources.

One straightforward way to measure the riskiness or robustness of a portfolio is to compare its expected cost to its worst-case cost. Northwest Energy and the Northeast Power Coordinating Council (NPCC) compare portfolios using this type of metric. They measure each portfolio's risk as the difference between its expected cost and an average

of the costs in the last 10% of the high end of its probability distribution, which they consider to be the worst-case cost.¹⁹

Another approach for quantifying risk is to calculate the increase in cost over a given planning horizon (the selected risk level) for a specified probability or risk level. This approach, Value at Risk (VaR), was developed in the financial sector to evaluate the downside risk of an investment. It is always calculated in the context of a risk level and a planning horizon. Value at risk is widely used by banks, securities firms, commodity merchants, energy merchants, and other trading organizations, who often monitor it on a daily basis. In the case of an electricity resource portfolio VaR can be applied to measure the cost increase that has a certain probability (the selected risk level) of occurring over the selected planning horizon. For example, a regulator might be interested in the VaR of a proposed resource portfolio over a one year planning horizon at the 99% risk level. That VaR would tell us the amount of extra cost that would have a 1% chance of occurring over the next year. Or, a VaR at the 90% risk level for a ten year planning horizon would tell us the amount of extra cost that the portfolio has a 10% chance of incurring over the next ten years. Utilities in California compare portfolios using this type of metric and variations on it.²⁰

Value at Risk and estimates of extreme values like the metrics used in Montana are two measures of the risk of a specific portfolio. There are several possible measures of risk available for regulators to consider. These are listed in Table 3.1 and discussed in Appendix D of this report. The goal of monitoring and managing each of these risk measures is to identify sources of and changes to risk and to enable managers and regulators to reduce overall utility risk for both utility customers and shareholders. Consistency and transparency should be considered in choosing a measure to use. It may also be necessary to require validation of the computer models used for this purpose, especially proprietary or in-house models. It is also important to exercise care in the development of the probability distributions used to generate the risk measurements.

¹⁹ Not surprisingly, the mechanics of computing this measure of uncertainty are far from simple. This approach is discussed further in Appendix B of this report and in the NorthWestern Energy 2005 *Electric Default Supply Resource Procurement Plan*, available at <http://www.montanaenergyforum.com/plan.html>

²⁰ See Appendix B of this report and CPUC Energy Division, *Workshop Report on Value at Risk, Cash-Flow at Risk, and Other Measures of Portfolio Risk*. June 6, 2003.

Table 3.1 Possible Measures of Risk

Value at risk	Estimates the likelihood that a given portfolio's losses will exceed a certain amount.
Component value at risk	Measures the marginal contribution to value at risk of each element within the overall portfolio.
Credit value at risk	Measures potential credit exposure on individual transactions as well as the total credit value at risk for the portfolio.
Enterprise-wide risk measures	Aggregates market, operational, credit, and regulatory risk.
Costs at risk	Measures probability that a portfolio's costs will go up or down.
Rates at risk	Measures potential change in end customer's rates as a result of generation supply portfolio.

3.5.2. Considering Risk in the Assessment of Resource Choices

The various parties involved in long-term planning, fuel and purchased power procurement, and ratemaking will have a range of perspectives and goals. From a regulatory perspective the goals may be to achieve a reasonable balance of cost and risk. In order to prepare a quantitative comparison of alternative resource portfolios relative to those goals, a regulator may wish to know the expected retail rates over the next two years *and* the amount by which retail rates could increase over that same period at a 90% risk level for each portfolio. Adaptations of the VaR measure discussed above can be used for this purpose.

Expected cost and value at risk could be used to help evaluate and compare three alternative strategies, e.g., (1) the status quo plus purchased power from the wholesale market, (2) building a particular new generating plant, or (3) a combination of increased DSM and smaller purchases of power from the market. These metrics would allow comparison of the three resource choices on their expected present value revenue requirement (PVRR), the usual measure looked at in IRP, as well as on the risk of rate increases. Regulators have always done such risk assessments mentally or implicitly; now they have tools for making these assessments quantitatively and explicitly.

This notion, of course, is based on the assumption that one can actually quantify the risk. As discussed earlier, future probability distributions are typically estimated based on an analysis of historical data. If the historical data is inadequate or does not represent current or future fundamentals, then the probability distribution will not be accurate. Some types of risk are well represented in historical data, such as interest rate fluctuations, returns on financial investments, and some commodity prices. Other risks are not well represented in historical data. For example, the additional price risk for fossil fuels due to potential carbon regulations would have to be analyzed separately, perhaps through a scenario analysis, and added to the underlying uncertainty in fossil fuel market prices.

There are of course ways to reduce the level of risk identified in any such analysis. For example one might sign a long-term fixed-price contract or purchase commodity futures. That would eliminate, or nearly so, the risk associated with increases in material costs, but it would also eliminate the potential benefits if those costs fell. There are also more sophisticated approaches using call and put options which can limit the downside risks but still capture the upside benefits. The most neutral approach is a “costless collar” in which the purchase and sales costs of the options net to zero. In essence, this is trading some of the upside potential to protect against some of the downside risk.

Thus, to summarize, all of the “at risk” calculations attempt to determine the likelihood and magnitude of the downside risks. The results are based on statistical models, usually reflections of historic performance of a given investment or market, and predict a “loss” threshold at a given probability level over a specified time period. The methodologies are most robust in the short to intermediate term for normal economic conditions. Unusual or new conditions can be factored in through additional analysis, but these require special studies.

3.5.3. Tools for Mitigating Risk

The goal of monitoring and managing each of these risk measures is to identify sources of and changes to risk and to enable managers and regulators to reduce overall utility risk for both utility customers and shareholders.²¹

Many kinds of risk can be protected against with insurance, although there is usually an increase in the expected cost for doing so. This is true for some resource types, but not all. For example, if one wishes to reduce exposure to the risk of possible climate change mitigation costs or emission permit costs, one could choose renewable resources over fossil fuels as a portfolio addition. At the current time, the expected cost of power from many renewable resource plants may be greater than the expected cost of fossil fuel plants over their respective lives. Hence, choosing that kind of renewable generation insures against a possible future cost at the expense of accepting an increase in the power cost that will occur if those climate change costs do not arise or arise late. However, there are possible “insurance” resources that do not incur extra costs. Many DSM resources are known to be cheaper in terms of lifetime revenue requirement than traditional fossil fuel generation (and the associated transmission costs and line loss costs), but also provide insurance against possible CO₂ emission costs. In addition, reducing a utility’s riskiness by making lower risk portfolio choices may reduce its cost of money and hence its overall cost of service.

²¹ For additional discussion of ways in which portfolio management can address electricity resource risk for regulated service or default service procurement, see Biewald, et al., 2003 cited above.

4. Tools and Data for Portfolio Management

4.1. Overview

Portfolio management activities can be grouped into three major applications or stages, as discussed earlier. These activities as indicated in the Introduction are

- developing a resource plan,
- procuring the portfolio of resources identified in that plan, and
- managing that portfolio of resources on an ongoing basis.

Some of the questions to keep in mind when considering the appropriate tools are:

- Over what timeframe will the proposed strategy apply?
- What level and stability of prices are expected to result during that time?
- What flexibility is there to modify the strategy in response to changes in demand or supply conditions, at what points in time is that possible, and what is the process for doing so?
- What alternative strategies were, or should be, considered?

The nature and scope of each activity may vary according to the entity responsible for portfolio management and its particular objectives, constraints and circumstances. For example:

1. Type of organization, e.g., vertically integrated utility or a load serving entity.
2. Scope of consideration, e.g., total cost of delivered services, generation service cost.
3. Planning objectives, e.g., rate minimization, rate stability, balance of rate minimization and rate stability, rates tied to day ahead prices.
4. Time frame for planning, e.g., decade or more, one to five years, less than a year.
5. Planning constraints, e.g., all new resources to be acquired from wholesale market, renewable energy target.

This section provides an overview of the data and software tools available for each major application and a brief discussion of the issues associated with each.

4.2. Tools Available for Portfolio Management

The software tools that are available come from two different perspectives (1) financial planning and investment and (2) traditional utility supply-side planning. The former flow from a highly developed quantitative practice and focus on the management of various financial instruments such as future contracts, laddering, and options. The software tools

available in this category offer fairly sophisticated methods for evaluating risk. Contrastingly, those models and tools coming from the utility side represent the unique aspects of the electric utility industry, but are *much less sophisticated* in risk analysis. The sections below describe the types of tools and Appendix C describes specific software tools in more detail. Table 4.1 provides an overview.

Table 4.1 Overview of software models for risk analysis and management

Application	Time Horizon	Input Data and Forecasts	Capacity expansion models	Procurement and scheduling models (no capacity expansion)
1. Integrated System Plan (analytics)	10 to 20 years (long-term)	Forecasts of <ul style="list-style-type: none"> • customer load, • price elasticity, • resource availability, • fuel costs, • resource costs, • risk premiums, • fuel price volatility, • reliability requirements and policies, • environmental policies and costs. 	<i>Optimization Models</i> Electric Generation Expansion System (EGEAS) EnerPrise Capacity Expansion	<ul style="list-style-type: none"> • PLEXOS for Power Systems
			<i>Screening, scenario, and risk analysis models</i> PowerBase Suite AURORA RISKMIN	
2. Procurement (Trading and Risk Management)	1 to 3 years (short-term)	Energy and fuel price forecasts and market futures. Load requirements.		BookRunner; Edur Epsilon & Entegrate ICTS Symphony Planning and Risk
3. Management (Generation and Scheduling)	Daily to annually (day ahead or near-term)	Short term load forecasts. Resource and transmission availability Fuel and energy prices Environmental conditions		Monaco Predict! Kidex Risk Workbench

4.2.1. Load Forecasting

Load forecasting has been done since the beginning of the electric utility industry. The approaches used vary by the time scale involved. Short-term forecasts of a day or less are based on typical hourly load patterns for the season and weather forecasts. Forecasts of a few years are generally derived from recent historic data and extrapolated with

adjustments for weather and simple external drivers such as population growth and planned DSM programs. Common current practice is to incorporate weather variability in computing confidence intervals for peak load levels. The greatest change has occurred with long-range forecasts. The old practice was to plot the historic load values on log graph paper and then draw a straight line into the future. More modern practices look at load growth by customer class and apply econometric methods to develop future values. In some cases the load components are broken down by end-use category. That approach is especially useful for designing and evaluating Demand Side Management (DSM) programs. Over the years, most entities have developed and refined their own custom tools for load forecasting.

4.2.2. Price Forecasting

With the move in recent years to wholesale markets, a number of tools have been developed that integrate load and price forecasting. Some of these are quite sophisticated and consider transmission constraints and locational prices.

There is considerable academic and professional literature on this topic. In recent years most efforts have been focused on short-term forecasting using such techniques as neural networks.

4.2.3. Integrated System Planning

Integrated system planning is about finding the right mix of supply and demand side resources that provide low cost and reliable electricity service, while also minimizing risks. This is much like the Integrated Resource Planning (IRP) that was done by utilities before deregulation. The goals are similar but the available components have changed somewhat.

4.2.4. Risk Analysis

In this category are applications focusing on various aspects of risk. The short-term products look at the more quantifiable risks associated with futures contracts and energy markets. A few of the more utility focused tools try to represent in some way the longer term risks. But that is conceptually a more difficult task since there is much greater uncertainty. For longer-term analysis, a scenario-based approach is most commonly used, but the challenge always is to make those scenarios diverse enough to capture a reasonable range of possibilities.

4.2.5. Managing Financial Resources and Contracts

An important aspect of portfolio management is organizing and managing contract information.

Some of the types of products that could be monitored with software tools include spot purchases, forward contracts, option contracts, and flexibility contracts. Each of these product types offers a different type and degree of pricing and flexibility.

The goal of portfolio management may be thought of as finding the optimal trade-off between price and flexibility through 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 create an even mix. The role of software for managing contracts and options is to monitor (perhaps on a daily basis) the cost and risk of the inventory of such products and to analyze purchases and sales that might improve the tradeoff. If a portfolio includes short positions or options, frequent analysis is needed to choose the best time to fill short positions or to exercise options (if at all).

There are many vendors offering various applications for this purpose and below we list a few of fairly wide use in the energy sector. Note also that this category also overlaps some with the risk management tools in the next section.

4.3. Strengths and Deficiencies of Tools for Resource Planning and Procurement

Some points to keep in mind with regard to software tools for IRP and PM:

1. Traditional electric industry tools have a utility cost-based engineering optimization perspective. This is also true of nearly all IRP tools whose goal is to determine the least-cost plan given various fairly fixed expectations about the future.
2. Most traditional planning models are deterministic and do not incorporate uncertainty. Thus their results, while optimal for a specified set of assumptions, may not be so if circumstances change. Traditionally scenario analysis has been used deal with these limitations, but the range of scenarios needs to be wide enough to adequately represent the range of possible futures. There is a general human tendency to expect the future to be a smooth continuation of the present, but a look at the past shows that that is not always the case. One approach is to double the range of what conventional wisdom says. Another approach is to consider some “far out” scenarios as stress testers for the plans that are developed.
3. Short-term uncertainty can be more easily quantified via statistical methods than long-term uncertainty. Thus sophisticated statistically based methods used in trading and risk management tools are more appropriate for shorter terms of up to one or two years, but are harder to apply to long-range analysis and planning, at least at the current state of the art. This is mainly because of the increasing uncertainty of projections as time spans grow.²²

²² The ENERGY 2020 platform takes a somewhat different approach that may be helpful in analyzing the risks of long-term uncertainties and strategies. Originally developed as a premier load forecasting model, it is one of the few end use models commercially available. However, its endogenous and bottom up approach to representing the performance of the utility and its load and resources through time allows it to offer an integrated system for IRP analysis including representation of various supply-side and demand-side options. It does not presume optimal functioning of the utility's dispatch, or

-
4. Most financial tools are focused toward the shareholder/manager perspective and not toward customers. Thus when such tools are used for utility PM there needs to be a refocusing on the implications for customers.
 5. Demand-side options and non-traditional resources (such as wind and solar) are not well represented in most models. Thus *special effort*, depending on the model used, may need to be taken to adequately include these choices.
 6. Societal benefits such as environmental externalities and employment impacts are not generally represented. If they are to be considered, they may have to be calculated externally to the PM models themselves.

It is important to remember what the model was designed to do and what necessary simplifying assumptions are built in to it. Careful review of key input data is always necessary and it is wise to remember that even the best of models fed the best available forecasts can provide only informed approximations of the future.

4.4. Things to Consider Before Selecting Software

Whenever selecting software, it is important first to prioritize the objectives and then to evaluate the available options in that context.²³

- Objectives: How well the software meets the designated goals.
- Involvement: The ultimate users of the software need to be closely involved in its selection.
- Transparency: Are modeling methods and algorithms well documented and visible to users and regulators?
- Software Characteristics:
 - Monitoring capabilities
 - Facilitation and documentation of risk assessment, testing, and remediation
 - Built-in version controls
 - Security and access controls
 - Electronic sign-off functionality
 - Audit trail documentation and traceability
 - Ability to customize input fields, reports, and templates
- Reporting Capabilities: Are the model results available in reports and formats that are easily understood and used?

resource expansion as many models do, but can represent imperfections in planning and their results. For risk analysis, it provides a broad, integrated platform to analyze a wide range of long-term uncertainties via Latin Hypercube sampling (an efficient type of Monte Carlo simulation).
<http://www.energy2020.com/energy.htm>

²³ Some of these criteria are from Anne Marchetti, *Beyond Sarbanes-Oxley Compliance: Effective Enterprise Risk Management*, John Wiley & Sons, 2005.

-
- Flexibility: How easily can the software be applied to meet new needs?
 - Support: Does the vendor provide training, fix problems and update the software as needs change?
 - Implementation costs: software, licensing fees, hardware requirements, implementation time, training costs, customization efforts/consulting. Complex models severely tax even high end computer hardware. Investments in the fastest computers and largest storage devices available are likely to result in considerable labor savings and faster, more responsive answers to modeling questions. In summary, regulators considering PM or IRP software acquisition, whether for their own use or by utilities they oversee, should focus on the prioritized goals and be aware that the largest expense is likely to be for the personnel to properly use the software.
 - Staffing Requirements: The biggest investment may actually be in hiring and training people to properly use the software for the desired objectives.

4.5. Data Requirements for PM

Depending on the type of PM activity chosen there will be different data needs. Some of this can be based on historic information, but the essence of PM entails making decisions about a future in the face of uncertainty. Thus, the data used in each PM activity are primarily forecasts or assumptions. Moreover, as with most forecasts, the longer the planning horizon the more uncertain the forecast. In some cases the PM tools may themselves generate these forecasts based on historic data, or other methods and tools may be used. But in either case, the development of the input data is as least as important as the modeling itself and should be carefully scrutinized.

Some major general categories of data required for PM are forecasts of:

- customer load;
- reliability requirement policies;
- customer price elasticity;
- resource availability (including energy efficiency and renewable energy);
- resource costs, both fixed capacity costs and variable operating costs including fuel prices;
- fuel price volatility;
- environmental policies.

Procurement and/or portfolio management decisions that are made in the short- and near-term require more detailed data than resource planning decisions made for the long-term. The types of detailed data required for those short- and near-term decisions are listed in the box below.

Requirements

- Load forecasts
- Customer price elasticity (reduced consumption, switching)
- Capacity requirements

Fuel Markets

- Historical fuel prices and volatility
- Forward market prices

Self- Generation, Efficiency and Renewables

- Production costs from own generation
- Energy efficiency availability and costs
- Renewable energy availability and costs

Wholesale Electricity markets

- Forecast costs of capacity, transmission, and ancillary services
- Forecast costs of congestion and of FTRs to hedge congestion risk
- Historical wholesale electricity prices and volatility in the region of interest—both on and off-peak
- Forward market price data for electricity
- Probability and impact of new environmental regulations, e.g., CO₂ controls
- Probability and impact of new reliability requirements, e.g., RPM policy in PJM

Financial Instruments

- Financial instruments and associated costs

Depending on the specific circumstances not all of these may be required, or other kinds of information may be required. Each situation needs to be analyzed considering the objectives and what data is relevant and available.

5. Expertise and Staffing for Portfolio Management

5.1. Staffing and Expertise for Portfolio Managers

Overall, the expertise of the organization should include the following knowledge, skills, and abilities relating to portfolio management, risk analysis and management, and IRP:

Knowledge:

- Detailed knowledge of the natural gas markets, electricity markets, regional transmission organizations, and FTRs
- Full understanding of the range of available supply and demand options (including renewables, energy efficiency, etc.)
- Working understanding of the engineering and operations functions required to get those supply and demand options on-line
- Full understanding of transmission related options, including RTO/ISO rules and costs
- Working knowledge of relevant accounting rules (including rules for transactions in derivatives and Sarbanes Oxley compliance)
- Full understanding of environmental regulation costs and risks

Technical Skills:

- Ability to develop or select and implement quantitative models for power trading, power marketing, and fuels hedging
- Ability to utilize statistical and modeling tools, which may require programming expertise, as well as standard spreadsheet and database applications
- Ability to perform quantitative analysis of risk exposure on a periodic (possibly daily) basis and a long-term basis regarding both financial and physical positions
- Ability to identify, evaluate, and understand actual and potential changes in markets to assess overall portfolio risks
- Ability to develop and evaluate risk mitigation options
- Ability to take part in financial trades, potentially on a daily basis
- Ability to translate the outcome of the portfolio into utility rates

Other Abilities:

- Ability to communicate complex issues and options to internal staff and external parties (regulators, shareholders, etc.) regarding the overall risks associated with the current portfolio, as well as modifications that can be made to decrease such risks
- Ability to develop and maintain a system to provide detailed, traceable records regarding all trades and risk management strategies

-
- Ability to prepare reports regarding the portfolio's valuation
 - Ability to report activities to FASB, the SEC, rating agencies, regulators, shareholders, and the public.

While it is definitely possible, and perhaps preferable, for a utility to take on all of the above responsibilities with regard to portfolio management, there is an alternative solution, which is to outsource the portfolio management function.

5.2. Staffing and Expertise for Regulators

Regulators can and do play multiple roles with regard to portfolio management strategies.

The four major roles, which may not all be performed by a given commission, can be broken down into the following:

1. Design of the portfolio (choice of supply/demand side resources, T&D resources, types of suppliers, types of contracts, hedging mechanisms, etc.)
2. Actual procurement of products (solicitation of contracts, making trades, hedging, etc. and regular oversight of the portfolio)
3. Ongoing oversight and adjustment of the portfolio design and procurement, either as regulator or as implementer of procurement
4. Audit and other regulatory oversight of the utility (or other responsible parties) regarding each of the above.

How involved regulators are in each of the above is state dependent. In Maine, for example, regulators are intimately involved in each of the four roles described above, whereas in other jurisdictions regulators simply oversee the utilities' activities after the fact. Most states with competitive retail procurement fall in between these extremes. For example, in New Jersey, the Board of Public Utilities *approves* the portfolio and procurement plan, as well as the results of procurement, while the utilities execute those plans.

Naturally, the skill set required of regulators involved in electric portfolio management varies considerably with the extent that they are involved in each of the roles. Regulators generally need to be highly analytical, knowledgeable about financial products (hedging instruments, forward markets, etc.), knowledgeable about the range of resources available at any given time and their general cost. As far as timing, the role that regulators play is on-going or cyclical. From first assessing key risk areas to developing options to mitigate that risk to implementing a strategy and monitoring that strategy, regulators play a dynamic role in managing utility risk practices. For a graphic to demonstrate the full range of roles, see Figure 5.1, below.



Figure 5.1. The role of the regulator in risk management is dynamic in nature.²⁴

6. Conclusion

Traditionally, utilities performed integrated resource planning by evaluating a wide variety of available (or expected to become available) supply-side and demand-side resources in order to meet current and future needs. The usual emphasis was on finding the combination of resources added gradually over a planning period that was *expected* to meet the need at the lowest present value cost to the utility and its ratepayers over the planning period. While IRP processes have strong similarities from state to state, the detailed requirements specified by utility commissions vary. These differences include details for treatment of energy efficiency programs, whether and how to include treatment of environmental and societal costs, mechanisms for public input, and treatment of the way risk and uncertainty are treated.

Wise investors and commodity purchasers generally employ some kind of portfolio management (PM) and an organized procurement process to choose from the huge variety of products available. Portfolio managers must choose from contracts of various lengths and starting dates, decide whether and how to use options and hedging products, and evaluate many other possible strategies. This task, as a whole, has features in common with the job of a mutual fund manager, who takes responsibility for investing money for others, such as the assets of a retirement fund or an individual investor. In that setting, some of the available choices are cash, stocks of various kinds, bonds of various

²⁴ Lucienne Robillard, “Integrated Risk Management Framework,” presented by the President of the Treasury Board, Canada, April 2001.

lengths and maturities from various issues (companies, governments, special purpose entities, etc.), interest rate futures, mutual funds, and so on. State-of-the-art PM uses detailed quantitative analysis to understand the uncertainty of cost and returns from different investment choices. The goal of this quantitative analysis is to assess and manage how different combinations of investments with varied kinds of uncertainty affect the return and risk profile of the portfolio as a whole.

Obviously, this is a very general concept. When applied to electric power procurement, there are specialized constraints and additional options such as building one's own generation or reducing one's need through procurement of DSM options. Up until the mid-1990s, vertically integrated utilities focused on building or buying generation and on DSM programs, so adding PM to IRP would have made a difference only in emphasis. More recently, two things have changed. First, the appearance of market trading in wholesale power and options for power, natural gas, weather, and emission permits have begun to widen the choices a utility can make in its resource planning to look more like the type of PM seen in financial and commodity markets. Indeed, some "vertically integrated" utilities have de-emphasized owning generation and instead concentrate on power purchasing. Secondly, competitive procurement of power for default service has begun to use PM-like features, such as contract laddering and purchasing from purely financial brokers who do not own generation.

A few state PUCs now require utilities to apply portfolio management with the goal of achieving reliable electric service at reasonable rates to customers over the long term, either for vertically integrated service or for default service procurement.

Arguably all electric utilities—vertically integrated and distribution-only—could benefit from placing greater emphasis on PM. 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. 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. Utilities, even in states with restructured electricity industries, may need to take another look at how and why to manage resource portfolios.

The great variety of new electricity and electricity-related products and tools available for managing resource portfolios and rapidly changing market conditions means that regulators have an opportunity to reassess their roles and expectations regarding the scope and nature of portfolio management applied in their state, regardless of whether it is a retail choice state or a fully regulated state. This report has reviewed the reasons for this conclusion, explained the key analytical and policy-making challenges, and reviewed the software and skills necessary to perform those functions. It should be emphasized, however, that markets, market rules, and product offerings have shifted and changed frequently for some time now, and show no signs of stabilizing anytime soon. Regulators should continue to monitor such changes and update their policies and practices accordingly.

Most of these planning models discussed in this report require special effort in order to include energy efficiency and renewable energy in their evaluation of resources. In addition, these tools would benefit from improving their methodologies for analyzing

long-term risks and comparing long-term decisions under uncertainty. For example, some existing optimization models require the representation of system operation to be simplified and limit the number of resources that can be considered in a model run. Such modeling constraints can prevent the long-term costs and benefits to consumers of a diverse mix of resources from being evaluated fully. The availability of the data these models require to do sound risk analysis is also problematic in some competitive situations, while the institution of competitive wholesale markets has improved data transparency in others. Regulators may wish to promote research and development on improvements in these areas.

Appendix A: Supply Acquisition Strategies For Default Service In States With Retail Access

A.1. Overview

For this report, we examined competitive processes for procurement of power for default service in several states and the District of Columbia, representing a range of approaches to default service procurement. Specifically, we looked into actions that states are currently taking to manage risk—primarily price risk—for default service customers. The common approach to managing that risk is through defining and overseeing the procurement process used by default service providers (also known as basic service providers and providers of last resort).

States using auction or RFP procurement typically procure different products for different classes of customers. For example, a fixed price, all requirements service, including energy, capacity and ancillary services, might be procured for residential and small commercial default service customers, while large commercial and industrial customers might be served under a procurement for fixed price capacity, with energy billed at spot market prices. In states that procure default service power for small customers under multi-year, fixed-price contracts, power for medium-sized commercial customers may be procured under fixed price, but shorter contracts.

In this Appendix, we focus on procurement approaches for residential and the smallest commercial customers, as such approaches present the most challenging concerns for risk mitigation policies.

A.2. Risk Management Approaches Used in Default Service Procurement

Having surveyed a number of deregulated states, we find that many, but not all, retail access states have adopted one or another form of contract laddering to manage price volatility. Contract laddering means that power is procured in staggered, multi-period contracts, instead of through a single contract, or several contracts, that expire all at once. When such a ladder of contracts is put in place, only a fraction of the total portfolio of electric generation contracts expires each cycle, and only a fraction of the supply needs to be replaced and re-priced. In practice, this means that the majority of a customer's generation rate is already locked in by pre-existing contracts; the full effect of trends or spikes in electric generation prices is buffered for default service customers. In most jurisdictions that use contract ladders, the cycle period is one year, and the most common choice for contract lengths has been three years. Figure A.1 shows a pattern of procurement over time for a simple ladder of three-year contracts with one-third of the load rolled over annually. A contract ladder of this type, whatever the length of its contracts and number of cycles, may require odd contract lengths when being initialized to allow for synchronizing contract expirations and future procurements with ISO or RTO planning years and the like.

Laddering is the main procurement strategy used by a number of states and utilities that pursue competitive procurements for their default service, particularly on the East Coast. Table A.1 presents the specifics of procurement schemes in the jurisdictions studied.

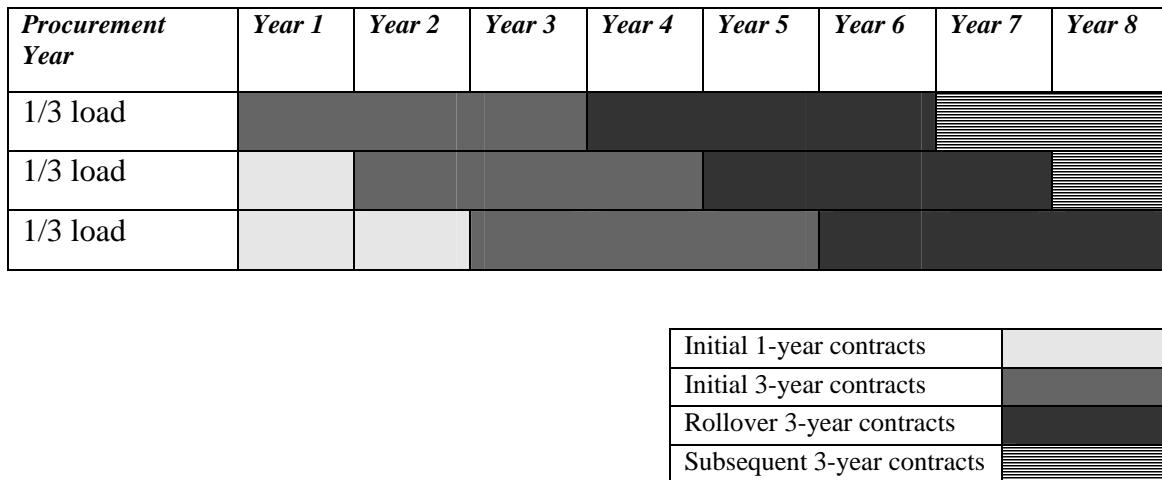


Figure A.1. Illustrative 3-year procurement ladder with phase-in. In this example, by Year 3, only 1/3 of the contracts expire and must be replaced each year. In other words, 2/3 of the load prices are locked in earlier years.

Specific laddering terms, such as those described above, are established via commission orders. In many cases, the framework used to establish such terms was a negotiated settlement amongst some of the parties to a rulemaking or other proceeding. Settlements have included varied parties, including some or all of the utilities, wholesale bidders, retail suppliers, regulators, consumer advocacy groups, and others. Generally, once the contract procurement ladder and process is established, adjustments have been made for a period of several years before it is revisited.

A.3. Observations on Procurement Approaches

A.3.1. Procurement Process

A few retail choice states rely primarily or in part on spot market purchases for default service procurement (e.g., Texas and New York). In New York, supply procurement for default customers is essentially a portfolio-based approach where utility supply portfolios typically consist of "legacy hedges" (i.e., long-term contracts entered into at the time the power plants were sold), short-term contracts, spot purchases from the NYISO market, and financial hedges. The majority, however, use either a Request for Proposal (RFP) or an auction format to procure power for default service customers. New Jersey led the way with auctions for default service power, using a descending clock auction to determine final prices. Illinois has recently adopted a similar process, but has not yet executed an auction. A number of other jurisdictions, including Maryland, the District of Columbia, Maine, and Delaware, use RFPs soliciting bids of various lengths for fixed price blocks of default service power.

Table A.1: Competitive procurement strategies for procurement of default service power in selected jurisdictions.

Jurisdiction	Procurement Process Type	Contract Durations	Effective Date of First Procurement	Timing of Procurements	% of Annual Requirements Procured
New Jersey	Auction	3-year	2002	Annually, in February	33%
Maine ²⁵	RFP	3-year	2005	Annually, in December	33%
Illinois	Auction	3-year	2006 (pending)	Annually, in September	33%
Maryland ²⁶	RFP	Mix of 1,2 and 3-year	2005	Annually, in 3 rounds, approx. 3 weeks apart. Previously began in Dec., but MD, DE and DC expect to reschedule so that bid periods do not overlap.	Varies. Currently 25% annually.
District of Columbia	RFP	Mix of 1,2 and 3-year	2005	Same as Maryland	Varies. Currently 25% annually.
Delaware ²⁷	RFP	3-year	2006	Same as Maryland	33%
Massachusetts ²⁸	RFP	1-year	2004 ²⁹	Semi-annually, in April and October	50%
Texas	Spot market	N/A	2002	Daily	Actual daily requirement
New York	Utility-specific portfolio approaches along with the use of financial instruments	Varies, some pre-existing long-term contracts, short-term contracts, spot purchases, and financial instruments.	1999	Varies	Varies

²⁵ New legislation (May 2006: 36 MRSA §3203) establishes the possibility of using longer-term contracts.

²⁶ The MD PSC is currently exploring changes to SOS procurement: [case number 9064](#).

²⁷ New legislation (April 2006: [H.B. 6](#)) calls for sweeping changes, including integrated resource planning, consideration of both short- and long-term contracts, owning and operating generation facilities, and demand side management program to serve default service customers. At least 30% of the requirements are to be procured competitively from the regional wholesale market. IRP aspects of this bill will be implemented over time, but a proceeding is under way to consider revisions to the RFP procurement process (PSC Docket No. 04-391).

²⁸ While Massachusetts has revisited contracting mechanisms multiple times over the last several years, most of the state's basic service providers continue to procure 50% of their load every 6 months, using 1-year contracts. However, in a December 2005 settlement, NSTAR agreed to begin using a mix of 1, 2, and 3-year contracts for its generation contracts going forward.

²⁹ Effective date of semi-annual procurements. Standard offer service began in 1998.

Advantages and disadvantages are claimed for each approach. State regulators or default service providers who utilize RFPs can readily adjust the RFPs annually to address specific needs or concerns over time. Smaller jurisdictions perceive an advantage in the RFP format due to reduced transaction costs and shorter lead times, viewing a more formal auction process as burdensome. Meanwhile, advantages of the auction include a perception of greater transparency, especially since bidders receive feedback about the level of interest expressed in each round of bidding as the price descends from round to round. To date, there is not enough data to clearly indicate which approach is better from either the generator or consumer perspective. Theoretical arguments have been offered about which one, if either, will produce the lowest prices, greatest bidder participation, etc., but, in practice, each approach has been able to attract a sufficient number of bidders to satisfy the various commissions that monitor the processes.

Some states (e.g., New Jersey, Maine, Illinois) have a single annual procurement to replace expiring contracts. Maryland, the District of Columbia, and Delaware each spread the annual procurement over three separate bid dates, spaced approximately three weeks apart in time. This is perceived to reduce the risk that a temporary market disruption will dominate the overall result. On the other hand, the smaller size of each procurement might make the RFP marginally less attractive to bidders and slightly increases the administrative cost.

The different approaches have advantages or disadvantages for both the buyers and suppliers, but there is not enough data available to reach firm conclusions on which approaches are better and under what circumstances. Clearly, however, timing plays an important role in the outcome of procurements. Default service procurements are typically scheduled farther in advance and are not easily moved. Market events and the timing of their procurements hit the 2006 generation contracts in Maryland, the District of Columbia, and Delaware particularly hard. These jurisdictions each held the first of their three intra-year procurements in December 2005, when natural gas price futures were at an all time high. Even a six week delay would have resulted in prices on the order of 20% lower. In this regard, New Jersey was fortunate, because its last procurement was held in February 2006, at which point natural gas prices (and electricity futures) had already begun to subside. Thus, the specific timing of procurement processes can significantly affect generation rate outcomes. Jurisdictions attempting to initialize a multi-year laddered procurement are particularly vulnerable. Whether results can be improved by introducing flexibility in the timing of procurements is a recent topic of controversy.

A.3.2. Contract durations in default service procurement

We see that not all states have chosen to implement the same contract laddering terms. New Jersey, Illinois, Delaware, and Maine have chosen a simple 3-year contract laddering approach.³⁰ The District of Columbia and Maryland use a combination of one-,

³⁰ New Jersey began with unladdered one-year contracts and began phasing in a three-year ladder with its 2003 procurement. In its 2005 RFP, Maine began to phase in a three-year ladder, but did so by procuring separately priced contracts for each off years one, two and three of the ladder, rather than single, flat-priced bids for the whole three years.

two- and three-year bids in their 2005 and 2006 RFPs. Meanwhile, Massachusetts utilizes only 1-year contracts in overlapping procurements every six months. In New York, some utilities use the laddering approach for a portion of their supply portfolios with the remainder of their portfolios consisting of longer-term contracts and spot purchases. Texas relies on spot markets.

The duration of contracts and the number of overlapping contracts in a laddered portfolio has a major affect on the degree to which customers are protected from price fluctuations; those procurements using spot market purchases or unladdered contracts (100% of contracts expire together) expose customers to greater price volatility than laddered procurements. Contracts for longer periods of time protect customers from price fluctuations longer, but if they are not laddered to roll over, create the risk of larger price jumps when they do expire.

In general, jurisdictions that use a three-year ladder with annual roll over of one-third of the supply have chosen to optimize their ladder to provide protection against fluctuations of price ranging from short-term spikes to highs and lows of up to a few years. With regard to the longer-term risks (say, price trends over five to ten years or longer), a ladder of three years or less is inadequate to mitigate those risks for customers. A three-year ladder results in generation rates that are, in effect, a three-year moving average of market prices. So, if generation prices gradually rise over ten years or if a market change results in a sudden long-term shift in prices, the risk mitigation obtained from early procurements fades out after three years and the full force of those market trends or events is fed into rates at that time. Price risks due to long-term trends or sudden permanent market shifts may be mitigated only with correspondingly long-term procurements (or other types of long-term hedging). In order to accommodate longer-term stabilization goals, a long-term ladder or longer-term resources would be needed.

It is important to note that a *single* long-term purchase stabilizes rates for the life of the contract, but at the risk that the contract may turn out to be higher than market prices that actually occur in the future *and* at the expense of total exposure to market conditions prevailing at the end of that purchase. Alternatively, the aspect of laddering that produces *risk mitigation* as well as *price stability* is that it divides the supply up into small increments, each of which is priced separately at a different time and only one of which expires at any given date.

It is also important to highlight the fact that states may have different policy objectives with regard to portfolio management. For example, states that have chosen contract laddering may have a goal of trying to stabilize prices for customers who do not switch to a competitive supplier or they may anticipate that small customers are unlikely to switch to a competitive energy supplier.

New York specifically desires to encourage development of competitive retail markets but requires utilities to provide stable prices for mass market customers until volatility mitigated products are available from the competitive market. The NY PSC's 2004 policy statement requires that utilities that provide default service, at least for the present, should "prepare plans to foster the development of retail markets" and "continue to maintain a

balanced contract portfolio for residential customer commodity" in the "near term."³¹ Pricing of default commodity service varies by utility and by customer class. Some utilities pass through average monthly NYISO spot prices in the supply charge but with an offsetting adjustment to delivery charges based on the "value" of hedges, so that, on average, the utility's commodity price is based on its overall portfolio cost.³² Texas has chosen a similar strategy to encourage competition. Most deregulated states, however, have opted to focus procurement policy on the needs of customers who do not shop.

A.4. Beyond Laddering

When contract laddering is the sole procurement tool used, it provides only limited portfolio management benefits, which are realizable only over the length of that ladder – sometimes a very short time frame. Some states are beginning to address this limitation through new laws that explicitly try to obtain low costs over the *long-term* for their smaller default service customers. A variety of means have been adopted or are under discussion for this purpose.

Maine is one state that has taken this approach. The Maine Legislature recently enacted legislation requiring the PSC to "adopt by rule a long-term plan for electric resource adequacy for this State to ensure grid reliability and the provision or availability of electricity to consumers at the lowest cost." The new legislation allows the Commission to include in that plan "cost-effective demand-side measures" as part of the supply of standard-offer service. It authorizes the Commission to enter into various standard-offer service contract lengths and terms for residential and small commercial customers and directs the Commission to consider developing one or more demand response programs for medium nonresidential customers."³³

Delaware now also requires expanded portfolio management practices embracing full scale integrated resource planning for default service including energy efficiency, renewables, and the option of utility construction of new generation units.

³¹ Quotations from pages 48, 52 and 28-29 of the *Statement* cited in this footnote, respectively. However, the Commission also declined to provide for further acquisition of hedges for medium to large commercial and industrial customer service as existing hedges expire. *Statement* at 32. Further, the Commission ordered that, "When new rate cases or rate plan extensions are filed, the utilities will be expected to include specific proposals to encourage migration of customers and to otherwise further the development of retail competitive markets....We are not endorsing the New Jersey [auction] model because it unnecessarily prolongs the utilities' commitment to multi-year wholesale contracts and their role as a commodity supplier.The sooner customers experience pricing variations, the sooner competitive markets will provide alternatives, including fixed-price options and peak and off-peak pricing, possibly accompanied by interval metering." NY PSC Case 00-M-0504, Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets and Fostering Development of Retail Competitive Opportunities. *Statement of Policy on Further Steps toward Competition in Retail Energy Markets*, August 25, 2004.

³² Personal communication, Raj Addepalli, NY PSC, 7/30/2006

³³ 36 MRSA §3203, enacted May 2006.

On or after May 1, 2006, it is the policy of the State that Electric Distribution Companies subject to the oversight of the Commission and as part of their obligation to be Standard Offer Service Suppliers shall engage in Integrated Resource Planning for the purpose of evaluating and diversifying their electric supply options efficiently and at the lowest cost to their customers....As part of the initial IRP process, to immediately attempt to stabilize the long-term outlook for Standard Offer Supply in the DP&L service territory, DP&L shall file on or before August 1, 2006 a proposal to obtain long-term contracts. The application shall contain a proposed form of request for proposals ("RFP") for the construction of new generation resources within Delaware for the purpose of serving its customers taking Standard offer Service. Such proposed RFP shall include a proposed form of output contract..., which contract shall have a term of no less than ten (10) years and no more than twenty-five (25) years. Such RFP shall also set forth proposed selection criteria based on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility and terms and conditions concerning the sale of energy output from such facilities.³⁴

Similarly, Maryland is considering modifications to its standard offer service policy. Objectives and strategies are currently being considered in Commission Case Number 9064: a major policy review proceeding covering the provision of standard offer service ("SOS") to residential and small commercial customers.

In sum, some states that deregulated electric generation and adopted retail competition in the last decade are returning to an IRP-type of portfolio management, as opposed to relying solely on contract laddering with terms of one to a few years. This may provide a more robust form of portfolio management than is currently being utilized.

A.5. Resources on state procurement practices

For more information on the basic service procurement processes and results in the states that use a competitive process for procurement of their default service, see:

- NJ: www.bgs-auction.com
- DE: http://www.state.de.us/delpsc/documents/dp_sos_022806.pdf
<http://www.state.de.us/delpsc/documents/vantage030106.pdf>
- MD: <http://www.psc.state.md.us/psc/AboutUs/Press/SOS2004.htm>
http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C%3A%5CCasenum%5C8900-8999%5C8908%5C462.pdf
- ME:
http://www.maine.gov/mpuc/industries/electricity/standard_offer/closed_so_solicitations.html

³⁴ Electric Utility Retail Customer Supply Act of 2006, HB 6, enacted April 2006.

-
- MA:
<http://www.mass.gov/dte/restruct/competition/defaultservice.htm#Fixed%20Default%20Service%20Prices>
 - <http://www.mass.gov/dte/restruct/competition/index.htm>
 - DC: http://www.dcpsc.org/pdf_files/hottopics/PEPCO_Press_Release_030306.pdf
http://www.dcpsc.org/pdf_files/hottopics/Q&A_PEPCO_New_Price.pdf
 - IL: ICC Final Order Dockets 05-0159 through 0162, January 2006.
<http://www.illinois-auction.com/index.cfm?fa=bid.reginfo>
 - NY: PSC Case 00-M-0504. Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets and Fostering Development of Retail Competitive Opportunities. *Statement of Policy on Further Steps toward Competition in Retail Energy Markets*, August 25, 2004.
[http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/0717FE125899AD1985256EFB006253F2/\\$File/201b.00m0504.pdf?OpenElement](http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/0717FE125899AD1985256EFB006253F2/$File/201b.00m0504.pdf?OpenElement)

Appendix B: Integrated Resource Planning Practices in Regulated States

In contrast to the practices seen in the deregulated states covered in Appendix A, the fully regulated states we surveyed generally had an integrated, active approach to portfolio management.³⁵ Frequently these processes consider many factors affecting the need for electric resources, such as generation and transmission siting, system reliability, efficiency and renewable energy, rate design, and fuel diversity.

California, Montana, Washington, and Oregon, for example, explicitly require consideration of price or environmental risk management in planning and procurement. However, each state's approach to regulating risk management practices differs. More than any other state in the survey, California prescribes how utilities treat regulatory (environmental and cost recovery) and price risk in utility resource plans and is actively involved in utilities' decisions about risk metrics and models. California is also the only state we interviewed that explicitly defines consumer risk tolerance in the context of procurement planning. With both regulated and deregulated utilities, Montana is an interesting case study of how risk management policy can translate from one regulatory construct (vertically integrated) to another (deregulated). Washington and Oregon require utilities to consider risk, but they leave risk management squarely in the hands of the utilities. Because cost recovery depends in part on the company's risk management practices, utilities have a large incentive to keep up with developments in risk management theory and methods. In Oregon, specific regulations concerning risk are currently unfolding. Although Washington has generally taken a hands-off approach to risk management policy, incentives to account for risk in procurement planning and acquisition processes have spurred extensive and sophisticated modeling of stochastic variables, providing a solid foundation for least-cost/least-risk decision making.

B.1. California

In 2003, following a tumultuous two-year period of testing customer choice in retail markets, the California Public Utilities Commission (CPUC) ordered the state's investor owned utilities to resume planning and procuring resources to meet consumers' electric load. The state's Long-Term Procurement Planning process (LTPP) is one part of overall resource planning, which is being coordinated and integrated with previously separate processes under the following headings: Community Choice Aggregation, Demand Response, Distributed Generation, Energy Efficiency, Qualified Facilities, Renewable Portfolio Standards (RPS), Transmission Assessment and Planning proceedings and Resource Adequacy requirements. Every two years, utilities are required to submit LTPPs detailing their projections of demand and laying out how they propose to meet

³⁵ For this survey, we reviewed background literature, regulations, and legislation on risk management practices and policies in fifteen US states and one Canadian province. We contacted the state public utility commission where we found indications that the state makes some explicit consideration of price or environmental risk management in its planning and procurement processes. In all, we contacted eleven and interviewed eight commission staff members.

that demand over a 10-year horizon.³⁶ Analysis underlying and presented in the plans must include sensitivity analyses for load growth as well as for gas and market prices,³⁷ and the proposed resource mix must meet the criterion of least cost-best fit.³⁸

California requires utilities to consider environmental factors, including the cost of future carbon reduction regulations, in their long-term planning and resource comparisons. Utilities are instructed to add \$8 per ton of CO₂ to the cost of fossil-fired resources for planning purposes (i.e., the adder is not used in ratemaking) to reflect the cost of climate change to California and to incorporate some of these resources' financial, regulatory, and environmental risks into resource decisions.³⁹ The goal of this requirement is to reduce California's dependence on fuel sources that pose considerable and increasing environmental risks.

Also addressing the environmental externalities and regulatory risk associated with fossil fuels, California directs utilities to prioritize demand-side and renewable resources in the planning process. Utilities are to follow the "loading order" established in the state's Energy Action Plan (EAP), which seeks to optimize energy conservation and resource efficiency while reducing per capita demand.⁴⁰ The EAP established the following priority list:

1. Energy efficiency and demand response
2. Renewable energy (including renewable DG)
3. Clean fossil-fueled DG and clean fossil-fueled central-station generation

The state and its utilities are meeting their goals for energy efficiency, suggesting that the planning process and loading order may have had some affect on procurement decisions. For example, SCE requested an additional \$38 million for efficiency programs, to meet an anticipated energy shortfall. However, goals for demand response and renewables have been somewhat elusive, in part due to perceived increased risk of contract failure by

³⁶ Liz Baldwin, *Regulatory Assistance Project Electric Resource Long-range Planning Survey: California*. May 20, 2005.

³⁷ Demand forecasts must include three levels of demand, with a high load forecast that is set at the 95th percentile. Scenario analysis of energy and gas costs is likewise to be evaluated at the 95th percentile. (CPUC, *Ruling and Scoping Memo 37116 in Rulemaking 04-04-003*, Jun 4, 2004)

³⁸ Liz Baldwin, op. cit.

³⁹ U.S. EPA. *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States*, April 2006. Available at <http://epa.gov/cleanenergy/stateandlocal/guidetoaction.htm>.

⁴⁰ State of California. *2003 Energy Action Plan*. May 8, 2003.

http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

The loading order originates in the 2003 *Energy Action Plan*, proposed by a joint subcommittee of the California Energy Commission, the CPUC, and another agency that is now defunct. These agencies approved the final plan, which required the State Energy Resources Conservation and Development Commission to conduct assessments to address public-interest energy strategies including "identification of policies that would permit fuller realization of the potential for energy efficiency, either through direct programmatic actions or facilitation of the market." The *Energy Action Plan* was required under SB 1389 (Signed Sep 14, 2002. Available at http://www.leginfo.ca.gov/pub/01-02/bill/sen/sb_1351-1400/sb_1389_bill_20020915_chaptered.html, accessed July 12 2006).

renewables, as well as transmission development and cost recovery risks. In part to address these problems, the CPUC combined long-term RPS planning with its general procurement planning proceeding (R.04-04-003). Also, it directed utilities to identify and conduct contingency planning addressing impediments towards meeting the RPS.⁴¹

Procurement plans are required to incorporate one or more procurement process features that, if adhered to, reduce the utility's risk of cost disallowances. These features include a competitive procurement process,⁴² a benchmark-driven incentive mechanism,⁴³ and a pre-established set of criteria on the acceptability and eligibility of procurement contracts for rate recovery.⁴⁴

Taking into account the parties' positions, the CPUC analyzes each plan and may approve, modify, or reject the plans. The Commission may require compliance filings to resolve any deficiencies in the plans. Inclusion of an element in an approved LTPP does not constitute pre-approval, per se; the IOUs must get separate authorization for turn-key projects, self-build, and supply contracts of five years or longer.⁴⁵

Procurement strategy is overseen by utility-specific Procurement Review Groups (PRG), which comment on (but neither approve nor disapprove) the details of each utility's proposed procurement processes and contracts (prior to their submission to the PUC for expedited review). PRG members include the PUC Energy Division, Office of Ratepayer Advocates staff, and interested parties who are not market participants, all subject to a non-disclosure agreement.⁴⁶ The Commission monitors procurement decisions via quarterly reports submitted by the companies. Utilities must also file monthly risk reports assessing consumer exposure to market risk.⁴⁷

Guidance on specific risk measures evolved from the time of the energy crisis. Citing VAR's widespread use in financial markets, in commercial software, and in utility holding companies' annual reports, the CPUC adopted SDG&E and PG&E's

⁴¹ U.S. EPA, op. cit.; Center for Resource Solutions Team, *Achieving a 33% Renewable Energy Target*, Nov. 1, 2005. Prepared for the California Public Utilities Commission. Available at http://www.cpuc.ca.gov/word_pdf/misc/Achieving_33_Percent_RPS_Report.pdf, accessed July 12, 2006.

⁴² The Commission, not the utility, specifies the format of that procurement process, as well as criteria to ensure that the auction process is open and adequately subscribed. If purchases are in compliance with the authorized process, they will be recovered in rates. (California SB 1037. Signed Sept. 6, 2005. Available at http://info.sen.ca.gov/pub/bill/sen/sb_1001-1050/sb_1037_bill_20050929_chaptered.html, accessed July 12, 2006.)

⁴³ If approved, this incentive mechanism would authorize the utility to procure from the market, depending on how the company performs relative to commission-authorized benchmark(s). The incentive mechanism should be clear and achievable. In addition, it should contain quantifiable objectives and contain balanced risk and reward incentives. (California SB 1037, op. cit.)

⁴⁴ Under this mechanism, the CPUC will conduct an expedited review of the proposed transaction's compliance with the approved procurement plan. (California SB 1037, op. cit.)

⁴⁵ Liz Baldwin, op. cit.

⁴⁶ CPUC, Decision 02-08-071 in Rulemaking 01-10-024, Aug. 22, 2002; CPUC, Resolution E-3857, ID# 2979, Dec. 18, 2003.

⁴⁷ U.S. EPA, op. cit.

recommendation for reporting portfolio cost risk using TEVAR, the value at risk to expiration.⁴⁸ Further, it required that the utilities file monthly portfolio risk reports reflecting estimated portfolio risk for each month on a rolling 12 month basis, on a quarterly basis for months 13-24, and on an annual basis for months 25-60. Seeking transparency and consistency in risk management reporting, the CPUC required validation of SCE's proprietary, in-house portfolio risk model.^{49,50}

Consumer risk tolerance, defined as the price that an average consumer would be willing to pay to reduce the risk of higher prices in the future, is specifically addressed in the context of procurement planning. For example, PG&E set a consumer risk tolerance level, measured by portfolio TEVAR, at one-cent per kWh over a rolling 12 month period in its 2004 short-term procurement plan.⁵¹

More recently, SB 1037 emphasized the role of risk management in procurement plans. Objectives of the plans were clarified and redefined to include providing an appropriate balance of price stability and price level in rates, and to allow utilities to enter into financial and other electricity-related product contracts for the purpose of moderating price risk associated with serving retail customers. This law requires utilities to assess their portfolio price risk and risk management policy, strategy, and practices, including specific measures of price stability, and to include these assessments in their proposed procurement plans.⁵² Furthermore, the utility must demonstrate that the procurement plan

⁴⁸ VAR stands for Value at Risk, a measure of the uncertainty of the value of resource portfolio. VAR is discussed in Section 3.5 and Appendix C of this report. TEVAR, or Value at Risk to Expiration, is a measure of risk over the entire holding period of the positions. It is of some interest that the confidence levels (e.g., 95% or 99%) to be used in these analyses were controversial. The CPUC has ultimately approved use of 85% levels on the understanding that more extreme confidence levels may be beyond the ability of the existing data to estimate in a stable manner.

⁴⁹ The Commission stated, “while we continue to believe that it is unwise to be overly prescriptive in directing utility risk management practices, we need to balance our preference for an “even-handed” treatment on procurement policy with an emphasis on transparency and consistency in risk management reporting. We recognize the importance of standardized risk reporting in order to measure ratepayer risk on an “apples-to-apples” basis and to ensure that utility procurement decisions will benefit all IOU ratepayers in an equitable and unbiased manner. Establishing a common benchmark is one way of ensuring that California’s ratepayers, regardless of utility, are equally protected from adverse risk, and thereby can reap the benefits of reliable energy at low and stable rates.” (CPUC Interim Decision D.03-12-062, in R 01-10-024, Dec. 18, 2003)

⁵⁰ The CPUC allowed SCE to use its model temporarily, contingent on the Company reporting on the methodology, assumptions, and formulas of the model. Validation would require an independent audit. If the model did not receive an unqualified model certification, SCE would be required to use a commercially available risk measurement model. SCE later questioned the ability of an independent reviewer to assess the internal validity of its model but was overruled. The Commission clarified that certification required a determination that all the features of the model work as advertised, that the model is mathematically sound, and that the assumptions utilized by the model are reasonable. (Interim Decision D.03-12-062 in R 01-10-024, Dec. 18, 2003)

⁵¹ PG&E’s STPP was essentially subsumed into its LTPP. (CPUC, Resolution E-3951. Sept. 22, 2005)

⁵² A portfolio should include “any utility-retained generation, existing power purchase and exchange contracts, and proposed contracts or purchases under which an electrical corporation will procure electricity, electricity demand reductions, and electricity-related products and the remaining open

will “create or maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.” SB 1037 also allows the commission to use funding to obtain independent consulting services to evaluate risk management and strategy.⁵³

B.2. Montana

In 1992, the Montana Public Service Commission (MPSC) enacted IRP guidelines that encourage electric utilities to develop and implement least cost planning. Five years later, restructuring legislation established customer choice and mandated the functional break up of Montana Power Company. Montana Power Company was later purchased by NorthWestern Energy (NWE), which became the default supply utility (DSU) in most of the state. The other major investor-owned utility, Montana-Dakota Utilities (MDU), which provides power in eastern Montana, was exempted from restructuring and remained a vertically integrated utility.⁵⁴ In 2003, the PSC enacted guidelines on long-term portfolio planning, management, and resource procurement for default service electricity supply. As a result, there are two separate planning processes applying to the two major service territories: traditional integrated resource planning (applicable to MDU) and electricity resource planning and procurement for default service customers (applicable to NWE).

IRP guidelines

Montana’s IRP guidelines provide a fairly comprehensive framework for conducting least cost planning and addressing a variety of costs and risk factors. The guidelines place strong emphasis on managing and reducing risks associated with resource choices in a manner that addresses environmental, societal, and ratepayer risks as well as risks to shareholders. The IRP rules require that utilities consider all available resource options, including DSM, and evaluate these options based on a broad range of resource attributes. Using “best available” methodology, resource plans should explicitly evaluate quantifiable and non-quantifiable environmental externalities, including the uncertainty and risk associated with future environmental regulations, uncertainty regarding the size and importance of external environmental costs, and environmental costs associated with continued operation of existing resources.

Although utilities determine the sources of risk using their own techniques and judgment, the IRP guidelines suggest that utilities consider these potential sources of risk:

- resource lead-time,
- water availability,
- future load growth,

position to be served by spot market transactions.” (California SB 1037, signed Sept. 29, 2005. http://info.sen.ca.gov/pub/bill/sen/sb_1001-1050/sb_1037_bill_20050929_chaptered.html)

⁵³ California SB 1037, op. cit.

⁵⁴PacifiCorp was also affected by restructuring. PacifiCorp sold its Montana service territory to Flathead Electric Cooperative. Rural electric cooperatives opted not to open their territories to competition.

-
- shortcomings of various forecasting methods,
 - performance and useful lives of existing resources,
 - costs and performance of future demand- and supply-side resources,
 - the rate of technological change,
 - future fuel availability and price,
 - the existence and social evaluation of environmental externalities, and
 - the future sociopolitical and regulatory environment.

The IRP guidelines also present a list of potential planning techniques for utilities to consider for managing risks associated with the above sources:

- assessing the risk of resource alternatives,
- developing resource options that increase scheduling flexibility,
- developing small, short lead-time resources that better match loads with resources and reduce the amount of, and period over which, capital must be invested to meet future load growth,
- diversifying the resource portfolio to allow adaptation to a range of future outcomes,
- managing loads to increase utility control over resource requirements,
- encouraging the acquisition of resources through competitive processes,
- incorporating consumer response to rate design into forecasting models,
- providing for public involvement and education in resource decisions, and
- maintaining a transparent integrated least cost resource planning and acquisition process (i.e., one which produces resource plans that can be reasonably understood by the public and the commission).⁵⁵

The guidelines require that demand-side resources be given special consideration in resource evaluation.⁵⁶ Utilities are required to weight and rank existing and potential

⁵⁵ Montana Administrative Rules, sub-chapter 20: Least Cost Planning – Electric Utilities. 38.5.2004

⁵⁶ The IRP guidelines also include provisions on sizing and evaluating demand side resource options. The impact of price-induced conservation (i.e. conservation undertaken by customers in the absence of any utility-sponsored program) should be accounted for either in the load forecast or as part of the total available resource. The revenue impacts of decreased sales resulting from demand-side resources are not added to cost of acquiring such resources. Also, in considering demand-side resources, until a point at which there are no market barriers or market failures that may interfere with investment in demand-side resources, as opposed to supply-side resources, demand-side resources are considered cost-effective up to 115% of the utility's long-term avoided cost. The total societal cost test and the total resource cost test are required elements of an IRP. (Montana Administrative Rules , sub-chapter 20: Least Cost Planning – Electric Utilities. 38.5.2004; Liz Baldwin, *Regulatory Assistance Project Electric Resource Long-range Planning Survey: Montana*. Sept. 29, 2005)

resources on the basis of, in part, their environmental impacts. In evaluating potential resource options, utilities should recognize protected areas and any areas inhabited by protected wildlife. Utilities are encouraged to recognize the positive externalities associated with resources that correct or reduce existing environmental damage. Furthermore, utilities should conduct sensitivity analyses to determine if more environmentally benign resource alternatives can provide equivalent benefits at a lower societal cost.⁵⁷

Special attention is given to consistency between the IRP and rate making processes in the IRP guidelines. The importance of this consistency is particularly emphasized for rate stability. In addition, IRPs must explicitly recognize rate design opportunities to develop demand-side resources.

While the determination of how to assess environmental externalities and risk factors is left to the utility, the guidelines do require that the utility clearly and thoroughly document the decision process for choosing resource options.

Default electric supplier procurement guidelines

Montana's largest restructured IOU, NorthWestern Energy, is subject to Montana's default electric supplier procurement guidelines.⁵⁸ These guidelines were developed with the following stated objectives:

- Provision of adequate, reliable default supply services, stably and reasonably priced, at the lowest long-term total cost
- Pricing that is both equitable and promotes rational, economically-efficient consumption and retail choice decisions
- A balanced, environmentally-responsible portfolio of power supply and demand-side management resources, coordinated with economically-efficient cost allocation and rate design
- Diversity with respect to resource types and contract durations
- Dissemination of information to customers regarding the mix of resources in the supply portfolio and corresponding level of emissions and other environmental impacts

⁵⁷ The screening process in Montana's IRP guidelines requires that the cost assigned to each resource reflect all relevant attributes. Attributes generally include those that influence utility costs as well as long-term societal costs, including risk and uncertainty. Other attributes to be considered are environmental externalities, the overall efficiency with which the resource produces energy services, administrative costs of acquisition programs, the cost effectiveness of the resource within the context of the utility system, reliability, and associated transmission costs. (Montana Administrative Rules, sub-chapter 20: Least Cost Planning – Electric Utilities. 38.5.2004)

⁵⁸ In NorthWestern Energy's territory, there is currently no competitive supply available for residential and small business customers. A statutory change in 2005 will allow entities to aggregate residential and small business customers, subject to regulatory approval. The Commission lacks authority to adopt portfolio rules for aggregators, but it may be approving some sort of planning guidelines in the future.

Each DSU is required to develop an Electric Default Supply Procurement Plan (EDSPP) to comply with these objectives. This plan is based on a comprehensive resource needs assessment, considering all aspects of customer load, resource availability, and product type availability. The plan must assess the resource diversity and flexibility of the existing portfolio, as well as the effect of cost allocation and rate design on future resource needs. To evaluate these factors independently of resource options, DSUs must employ rigorous computer modeling and analysis in the portfolio management and resource procurement processes. Analyses must also be used to develop least-cost scenarios and conduct risk sensitivity analyses for the various options. Table B.2.1 shows the risk factors that DSUs are required to consider.

Table B.2.1. Sources of risk that should be considered in prudent default supply resource planning and procurement (MT 38.5.8219)

Underlying Risk Factor	Price Uncertainty Risk	Load Uncertainty Risk
Fuel prices and price volatility	X	X
Environmental regulations & taxes (including carbon regulation)	X	X
Default supply rates	X	
Competitive suppliers' prices	X	
Transmission constraints	X	
Weather	X	X
Supplier capabilities	X	X
Supplier creditworthiness	X	
Contract terms and conditions	X	X

DSUs must apply cost-effective resource planning and acquisition techniques to manage and mitigate the risks posed by the factors shown in Table B.2.1, above. Such techniques include contingency planning, portfolio diversification, and transparency in the planning and procurement process. These utilities must balance environmental responsibility with other portfolio objectives, including lowest long-term total cost, reliability, and price stability.

The guidelines require DSUs to develop methods for incorporating portfolio objectives into the resource procurement, for example by weighting resource attributes and ranking bids in competitive solicitation processes. The guidelines suggest that weights may be given to reflect, among other things, contributions to achieving optimal resource diversity; project feasibility (and risk) with respect to engineering, development, and financing; supplier creditworthiness (counterparty risk); and fuel source, associated price volatility, and regulatory risk (including regulations on carbon emissions).

A default service provider should evaluate the performance of alternative resources under various loads and resource combinations through scenario, portfolio, sensitivity, and risk

analyses. As an example of these modeling efforts, for its 2005 EDSPP, NWE conducted a 20-year horizon resource planning analysis involving the following steps:

1. Define the load obligation
2. Accumulate data on resource options and model inputs, including expected carbon costs and gas and electricity price forecasts
3. Create portfolios of resources that are representative of the feasible possibilities that NWE could pursue
4. Conduct intrinsic analysis⁵⁹ of the portfolios to identify key risk drivers, and employ scenario analysis for gas and electricity prices, load, and CO₂ regulations⁶⁰
5. Select the most robust portfolios, considering the major risk factors inherent in the portfolios
6. Conduct the final screening of the most robust portfolios using stochastic analysis using thousands of simulations
7. Select the best portfolios based on their placement on a risk-adjusted mean efficiency frontier⁶¹
8. Conduct qualitative analysis of the best portfolios
9. Create an Action Plan outlining how the selected resource characteristics will be acquired over the time frame of the Plan

NWE ran PCI GenTrader®, an energy supply portfolio modeling and generation dispatch model, for steps four, six, and seven (listed above).⁶²

For approval of a power purchase and sale agreement, NWE employed somewhat different methodology. NWE used GenTrader® to model both the current portfolio of resources and the best portfolio mix going forward. Also, it evaluated portfolio performance by a different measure of portfolio risk measure, calculated by adding 70

⁵⁹ Intrinsic analysis employs fixed market prices and static resource assumptions. (NorthWestern Energy, *2005 Electric Default Supply Resource Procurement Plan*)

⁶⁰ The analysis considers the potential implementation of a CO₂ tax using forecasts of medium, high, and zero taxes. The expected case (medium) was drawn from NPCC's estimate of a 67% chance of a \$6.00/ton-CO₂ charge starting in 2010 and rising to \$14/ton in 2017. *Ibid.*

⁶¹ For step seven, NWE employed a risk metric that compares the expected outcome (the mean) to the difference between the mean and the average of the worst 10% of stochastic draws. NPCC also uses this metric. *Ibid.*

⁶² GenTrader® is a “widely used” tool that evaluates complex power portfolios of both generators and energy contacts. In the MPSC’s Comments, it noted that other models might be more useful in this context—for analyzing and evaluating dynamic resource portfolios—because it does not employ iterative modeling techniques. *Ibid.*

percent of the stochastic mean portfolio cost to 30 percent of the 95 percent confidence level portfolio cost.⁶³

The default electric supplier procurement guidelines also address staffing and tools for risk management and mitigation, but only briefly. They recommend that utilities seek upfront and substantive input from an independent advisory committee of technical and public policy experts, for the purpose of mitigating risk and optimizing resource procurement outcomes relative to portfolio objectives. The guidelines also advise utilities to employ “adequate” staffing and technical resources for risk management; other suggested tools include using diversity (fuels, technology, contract terms) and contingency planning. Transparent planning and procurement process is also considered a cost-effective resource planning and acquisition technique for managing and mitigating risks.

As a requirement of providing default electric supply service, a default supplier is required to also provide customers with the option of choosing a “green” product composed of or supporting power from certified environmentally preferred resources such as wind, biomass, solar, or geothermal resources. Further promoting resource diversity, the Montana PSC recently adopted a rule establishing a Renewable Energy Resource Standard.

The Montana PSC is not required to explicitly “approve” resource plans filed by restructured or traditional utilities, therefore recoverable costs associated with an implemented plan are not guaranteed in rate cases.

B.3. Washington

The Washington Utilities and Transportation Commission (UTC or Commission) considers utility portfolio and risk management practices in three interrelated processes: integrated resource planning (IRP), competitive resource acquisition, and, more tangentially, in cost recovery.

In 1987, Washington implemented an IRP process with filings required every 24 months. As a part of the IRP process, utilities must conduct a “detailed and consistent” analysis considering, at a minimum, resource cost, dispatchability, and effect on system operation; market-volatility and risks imposed on ratepayers; uncertainties regarding demand-side resources; regulation or policy change at the state and federal level; and environmental policy risks, including the cost of CO₂ emissions.⁶⁴ The Commission does not require that IRPs consider externalities explicitly, although these issues may be considered in other proceedings.⁶⁵

⁶³ MTPSC Docket 2004-3-45, Order 6557c.

⁶⁴ WAC 480 100 238.

⁶⁵ Utilities that have service areas in other states that require consideration of externalities generally include these factors in their Washington IRPs. Liz Baldwin, Regulatory Assistance Project, *Electric Resource Long-range Planning Survey: Washington*. Sep 2005. Available at <http://www.raponline.org/>.

In the IRP process, utilities must consider a wide range of commercially available, conventional and non-conventional supply- and demand-side options.⁶⁶ This directive for an inclusive review of resources, together with risk evaluation requirements, spurred utilities to begin conducting extensive simulation analyses of many different resource portfolios, each over many different futures. For their IRPs, utilities compare the performance of these portfolios, allowing selection of one with minimal cost and risk for a given price and risk tolerance.

Although utilities are not specifically required to include DSM in resource portfolios, they have begun to do sophisticated analyses to more accurately represent the cost reduction and risk mitigation benefits that DSM brings to a portfolio.⁶⁷ For example, in its 2005 IRP, Avista analyzed conservation measures using hourly avoided costs (as opposed to the more common use of annual figures), load shifting, and on-peak versus off-peak value.⁶⁸

Risk management practices in Washington have improved greatly in the last five years, due to use of stochastic (and other) models and the availability of computing power to produce more robust results. Generally, the present value of revenue requirements is computed over many trials (200-300 iterations), and the mean of the variants provides a measure of risk.⁶⁹ For example, Puget Sound runs an enterprise-wide database management tool—KW3000 by Kiodex—as its core risk management software that is used to run large numbers of scenarios and to evaluate the firm's position.⁷⁰ While many risk factors, including weather and price variability, are evaluated using stochastic analysis, some risk factors are generally not considered stochastically; potential policy changes, for example, are generally evaluated using scenario analysis.⁷¹

The purpose of the IRP is largely for dissemination of information within the company and to the UTC, ratepayers, investors, and other stakeholders. If the Commission finds

⁶⁶ Although transmission and distribution are not explicitly evaluated in IRP, they are generally considered if they are impact or are impacted by other measures. Liz Baldwin, *op. cit.*

⁶⁷ The risk mitigation benefits that energy efficiency, other DSM, or renewable resources provide are accounted for in the IRP through a "consistent" comparison of all resources and extensive analysis of the performance of portfolios with different resource mixes under varying conditions. Washington does not confer special status to these resources in the resource planning and acquisition processes on the ground that their effects on risk vary. For example, while renewable resources may provide an excellent hedge against the price of fuel, they may have less value in terms of reliability, price, supply, and strategic risk mitigation. Phone interview, Hank McIntosh, WA Utilities and Transportation Commission, Integrated Resource Planning. Jan. 27, 2006.

⁶⁸ Linda Anderson, "Avista Utilities aims high on efficiency," *nwcurent*. Nov 29, 2005. <http://www.nwcurent.com/efficiency/industrial/1978117.html>

⁶⁹ Phone interview, Hank McIntosh, WA Utilities and Transportation Commission, Integrated Resource Planning. Jan. 27, 2006. See also Northwest Power and Conservation Council (NWPCC) 2003. *Power Supply Adequacy Forum: State IRP Requirements and Issues*. Available at <http://www.nwcouncil.org/energy/powersupply/adequacyforum/>

⁷⁰ Possibly relating to the large number of scenarios, the software has been cumbersome and slow in practice. Moreover, it needs a lot of input and time. (Phone interview, Hank McIntosh, WA Utilities and Transportation Commission, Integrated Resource Planning. Jun. 28, 2006.)

⁷¹ Liz Baldwin, Sep 2005(b), *op. cit.*

that an IRP is consistent with its rule, it issues an acknowledgment during a public, non-litigated process. This formal acknowledgment does not, however, represent a determination that a plan is reasonable, nor does it reduce the utility's regulatory risk in future proceedings, *per se*. Utilities are expected to justify resource procurement decisions in rate cases in light of any new opportunities or conditions that occurred after the IRP was issued.

Utilities are given a great deal of leeway in the methodology and assumptions used in developing their IRPs. A utility may, for example, choose the planning horizon (although long-run and short-run components are required), the assumed cost of compliance with CO₂ regulations, and acceptable levels of reliability and price escalation risks.⁷² Utilities can choose to reject Staff's technical advice on modeling methods⁷³ but rarely do so. To the extent that decisions subject to prudence review are founded on the IRP, it is in the utility's interest that Staff and other interested parties understand the proposed plan, including underlying modeling and assumptions, sufficiently well to participate in the plan's development. For this reason, the utility usually involves these parties the plan's development and may revise the plan multiple times based on their feedback.

While risk over the long term is generally dealt with in the context of the IRP, short term risk may be considered in other ways. At Avista, risk management policies focus on an 18-month horizon, consistent with available product terms and the uncertainty associated with hydro conditions.⁷⁴

Following submission of its IRP, the utility submits a draft request for proposals (RFP), consistent with the resource needs and preferences identified in the IRP but open to all resources, as well as a set of bid evaluation criteria for Commission approval or suspension. The evaluation criteria and ranking process for proposals must also be consistent with the stated goals of the IRP and include consideration of a resource's cost, dispatchability, and effect on system operation. In addition, RFP evaluation should consider risks to both shareholders and ratepayers with, for example, criteria for credit and financial risk, price volatility, climate change regulatory risk, and resource preference under federal or state policy. Finally, ranking criteria must consider unique risks posed by different technologies, fuel sources, financing arrangements, and contract provisions.⁷⁵

Bidder response to the RFP provides data for verifying the accuracy of resource cost and availability models and assumptions used in the IRP, such that these models and assumptions can be improved for future planning purposes.⁷⁶ The RFP data inform the utility's decisions going forward, and the Commission may use this information when evaluating utility performance during rate cases.⁷⁷

⁷² WUTC General Order No. R-526, Jan. 4, 2006, Docket UE-030311.

⁷³ Liz Baldwin, *Ibid*.

⁷⁴ Phone interview, Rich Stevens, Director of Corporate Risk Management, Avista. Jun. 30, 2006.

⁷⁵ WAC 480-107-015, -025, -035

⁷⁶ The results of the RFP are also used to determine the utility's avoided cost, which serves as the price to be paid to qualifying facilities under PURPA.

⁷⁷ WAC 480-107-015, -025, -035

Risk and risk management policy are also considered during prudence reviews. Utilities bear the full weight of their decisions regarding risk and price-risk tradeoffs, and they must later defend these choices during prudence review. There is no pre-approval.⁷⁸ Utilities have risk management policies, but they are voluntary⁷⁹ and produced within the companies. For example, Avista's risk management policy is written and approved by its portfolio management committee, comprised of upper management at Avista. Avista shares risk management policies with certain regulators subject to the confidentiality agreements. Although regulators provide comments, they have taken a hands-off approach to the development of these policies.⁸⁰

B.4. Oregon

Since 1989, Oregon has required investor-owned gas and electric utilities to file individual integrated resource plans with the Oregon Public Utilities Commission (OPUC) every two years.⁸¹ The primary goal of Oregon's IRP process is to acquire resources at the least cost to the utility and ratepayers in a manner consistent with the public interest. These resource plans must consider risk and cost-risk tradeoffs. Utilities have employed risk factors such as price volatility, weather, and the costs of current and potential federal regulations, including regulations that address CO₂ emission standards.^{82,83} In recent years, the utilities have considered non-quantifiable issues that impact planning, such as potential changes in market structure, the establishment of renewable portfolio standards, changes in transmission operation and control, and the effect of PacifiCorp's multi-state process on regulation and cost-recovery.⁸⁴

⁷⁸ NWPCC 2003

⁷⁹ Phone interview, Hank McIntosh, WA Utilities and Transportation Commission, Integrated Resource Planning. Jan. 27, 2006.

⁸⁰ Phone interview, Rich Stevens, Director of Corporate Risk Management, Avista. Jun. 30, 2006.

⁸¹ The original IRP order, No. 89-507, was modified in 1993 in Order No. 93-695, which set out guidelines for utilities to quantify external societal costs. In 93-695, the PUC found that mandating consideration of externalities was outside of its jurisdiction unless these costs are likely to be internalized in the future. Accordingly, the guidelines recommend that utilities incorporate cost adders to account for potential federal-level carbon regulations.

⁸² In its most recent IRP, PacifiCorp looks at four primary risks: load variation, natural gas and electric price variation, hydro variation, and forced outage rates. It also conducts scenario analysis for some "what if?" risks. For example, CO₂ risk was considered in a scenario analysis, which employs simpler models than are used for analysis of the primary risks. (Phone interview, Maury Galbraith, OPUC Energy Division. Feb. 3, 2006)

⁸³ Although Oregon is covered by the federally-mandated Northwest Power and Conservation Council (NWPCC) plan, Oregon utilities only consider this analytically sophisticated plan peripherally in the IRPs. Northwest electric power and conservation plans are available at <http://www.nwcouncil.org/library/Default.htm>.

⁸⁴ U.S. EPA. *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States*, April 2006. Available at <http://epa.gov/cleanenergy/stateandlocal/guidetoaction.htm>.

In docket UM 1056, the OPUC is currently considering changes to its IRP requirements and guidelines. The most recent proposal, put forth by Staff in docket UM 1056 includes these requirements and guidelines, in part:⁸⁵

- Utilities should evaluate all supply- and demand-side resources on a consistent and comparable basis, using consistent, clearly defined assumptions and methods for evaluation of all resources. Utilities should provide a comparison of resource fuel types, technologies, lead times, in-service dates, durations, and locations in portfolio risk modeling. Demand side resources should be evaluated on par with supply side resources, and any potential savings in distribution system costs from these resources should be identified.
- Uncertainty and risk must be considered in the IRP. At a minimum, utilities should address uncertainty due to load requirements, hydroelectric generation, plant forced outages, natural gas prices and electricity prices. Utilities should identify in the plan any additional sources of uncertainty. The analysis should recognize the historical variability of these factors as well as future scenarios. Discussions on specific risk evaluation metrics are ongoing.⁸⁶
- The primary goal is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its ratepayers.⁸⁷ To this end, utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource. The plan should include analysis of current and estimated future costs for all long-lived resources (such as power plants) as well as short-lived resources (such as short-term power purchases) for a planning horizon of at least 20 years. Utilities are required to address risk by analyzing resource alternatives using measures of cost-variability and the severity of bad outcomes, and by evaluating portfolios for a range of discount rates. These plans must analyze the effect of potential compliance costs related to global warming on costs and risks for the resource portfolios under consideration, as well as risk mitigation strategies.⁸⁸ The plans should also consider how costs and risks are affected by the use of physical and financial hedges.

⁸⁵ Staff's Reply Comments, filed Sept. 30, 2005 in docket UM 1056 (Public Utility Commission of Oregon)

⁸⁶ Currently, the risk techniques employed in IRP are not consistent with those used in ratemaking processes. That could change in the future. Staff and PGE are investigating whether IRP tools could be used to normalize costs for ratemaking purposes. Phone interview, Maury Galbraith, OPUC Energy Division. Feb. 3, 2006 and Jun. 28, 2006.

⁸⁷ To achieve the best combination of resources, utilities trade off cost and risk, with the understanding that it might be worth it to pay more for a portfolio that displays less volatility. (Phone interview, Maury Galbraith, Jun. 28, 2006. Op. cit.)

⁸⁸ Utilities are including a CO₂ adder as a base-case assumption, in addition to running CO₂ cost scenarios for a range of prices (\$0 to \$40/ton, 1990\$). In its 2006 planning cycle, PacifiCorp is looking at phase-in strategies where the CO₂ adder ramps up over time.

Additionally, the Staff's proposal continues the requirement that the public be allowed adequate involvement in development of the plan.

A parallel docket, UM 1182, is updating competitive bidding guidelines for resources above a certain size, including how bids should be evaluated and how bidding should mesh with IRP processes and criteria. Price-risk tradeoffs are also at issue in yet another open docket, UM 1066, which is reviewing whether the Commission should modify its requirement that all new generating resources go into rates at market price (undefined), rather than in the utility's rate base at cost. The current rules include a waiver process.

Currently, the Commission reviews the filed IRP—including its treatment of risk—and either acknowledges it, in whole or in part, or sends it back to the utility for modification and resubmission. Although the OPUC does consider IRPs in future rate-case proceedings, a formal acknowledgment of an IRP does not ensure favorable rate-making treatment for costs associated with resource acquisition.^{89,90} The significance of acknowledgment for future prudence review has been raised in UM 1056.⁹¹

Risk is also considered during rate cases on power costs, and adherence to companies' risk policies has made an impact on rate treatment. For example, the OPUC determined that PGE imprudently deviated from its risk policy when it contracted for power before forward markets demonstrated liquidity. The OPUC disallowed the difference between

⁸⁹ Oregon PUC Order No. 89-507 set forth the Commission's role in reviewing and acknowledging a utility's least-cost plan. The Commission reviews the plans submitted by utilities and either acknowledges them, in whole or in part, or returns them for modification, based on its assessment of the plans' adherence to the principles set forth in this and more recent orders. Legally, the Commission is required to reserve judgment on rate-making issues. However, the Commission considers the IRP and ratemaking processes to be linked. In ratemaking proceedings, the Commission gives weight to actions that are consistent with an acknowledged IRP, and utilities are expected to explain actions that are inconsistent with acknowledged plans. (OPUC Staff Report. April 18, 2003. Docket No. LC 33. <http://www.oregon.gov/PUC/meetings/pmemos/2003/050703/reg3.pdf>)

⁹⁰ Acknowledgment of specific risk management practices have been proposed. For example, PGE's Action Plan Supplement in case LC 33 requested acknowledgement of PGE's continued reliance upon ratemaking tools, including internal insurance, reserve funds, and deferred accounting, for managing risks that have a low probability but a high cost to insure externally. Staff opposed acknowledging this practice, because "different risk mitigation tools are appropriate for different resource acquisition strategies," further stating that Staff "cannot assess how PGE should mitigate risk because it will not be requesting acknowledgement of specific resource acquisition actions until it files its Final Action Plan." PGE later withdrew this request. (OPUC Staff Report. Op. cit.; OPUC, Partial Plan Acknowledgment, Order No. 03-461, Aug. 1, 2003)

⁹¹ In UM 1056, Staff initiated discussion on the significance of acknowledgment for a prudence hearing or rate case regarding an investment or purchase. Both PGE and PacifiCorp (and other parties, including Idaho Power) submitted comments. PacifiCorp maintained that what is known or knowable by the utilities is appropriately considered in the IRP planning cycle and asked the Commission to clarify that it won't revisit what was known or knowable at the time the IRP was acknowledged in later proceedings. (PacifiCorp's Opening Comments. Sept. 9, 2005. Docket UM 1056, p. 21-22) Staff opposes PacifiCorp's proposal. (Staff's Reply Comments, filed Sept. 30, 2005, in OPUC docket UM 1056.)

the actual purchased power costs and what costs would have been, had PGE followed its purchasing guidelines.⁹²

Although Oregon does not require utilities to have risk management policies, all investor-owned utilities (Idaho Power Co., PGE, and PacifiCorp) have them. Generally these policies are developed and approved by risk management committees consisting of company staff.

Risk metrics employed vary from utility to utility, although value at risk (VAR) and the variance of portfolios' PVRR is commonly used for resource planning. In its 2004 IRP, PacifiCorp evaluated resource portfolios using the following measures of PVRR variability: stochastic average PVRR (stochastic variable costs plus the deterministic fixed cost), upper tail PVRR (average of five worst results), and standard deviation and variance. As with metrics, risk management software also varies from utility to utility. Portland General Electric has just begun using Aurora for resource planning models. PacifiCorp uses Planning & Risk by Global Energy Decisions and adds on internally-developed, system-specific models for its IRP.⁹³

Formal treatment of risk allocation between shareholders and ratepayers generally occurs during rate cases. In these proceedings, a company's recovery of costs hinges on the prudence of its decisions based on information reasonably available to it on, among other things, the risk those decisions pose to consumers.⁹⁴ In theory, rate cases deal with risk to shareholders through the rate of return, but in practice this relationship is not specifically modeled. In recent filings, some intervenors argue that there should be reduction in the rate of return if the companies are granted purchase cost adjustment eligibility or other measures that reduce utility risk.

Most staff members at the Commission who deal with energy risk management are economists, with skills and experience in economic and financial analysis, return on equity, and cost of capital.⁹⁵

⁹² OPUC Order 02-772. Oct 30, 2002. Case docket UE-139.

⁹³ Our respondent has not used Planning & Risk but notes that the training provided by the software developer was excellent. (Phone interview, Maury Galbraith, June 28, 2006)

⁹⁴ Allocation of risk was also considered in docket UE 165, specifically with respect to PGE's request for a power cost adjustment mechanism (PCAM) to help it deal with the fluctuations in earnings due to hydro availability and power market prices. Under a rejected stipulation, the PCAM would have created an asymmetrical band around System Dispatch Cost Variance, in which consumers would have been charged for these costs in excess of \$15 million, whereas shareholders would return excess earnings greater than \$7.5 million to ratepayers. Among other things, this stipulation would have required PGE to obtain consultation services for analyzing the statistical distribution of net power costs as well as the variability and correlations between hydro generation, electricity prices, natural gas prices, system load, and forced outages. In its order rejecting elements of the stipulation, the Commission cited the stipulating parties' failure to provide analysis on how often the PCAM would likely be triggered and that it would be revenue-neutral. (Order No. 05-1261, Dec. 21, 2005).

⁹⁵ Cathie Murray, Regulatory Assistance Project, *Electric Resource Long-range Planning Survey: Oregon*. September 2003. Available at <http://www.raponline.org/>.

Appendix C: Models and Tools for Portfolio Management

C.1. Overview

This appendix discusses several computer models for portfolio management and some practical issues concerning the selection and use of such models. The particular models presented are some of the better known ones, but an exhaustive list is beyond the scope of this report.

In considering available tools for portfolio management in the context of electricity, several factors must be considered:

6. Type of organization, e.g. integrated utility or a load serving entity
7. Time frame for planning, e.g. less than a year, several years, decade or more
8. Scope of consideration, e.g. management of energy and fuel contracts or total cost of delivered services
9. Perspective, e.g. shareholders, customers, or society—or a combination thereof

The tools that are available come from two different perspectives (1) finance/investment and (2) traditional utility planning. The former flow from a highly developed quantitative practice and focus on the management of various financial instruments such as future contracts, laddering, and options. The software tools available in this category offer fairly sophisticated methods for evaluating risk. Contrastingly, those models and tools coming from the utility side tend to focus on fully representing the unique aspects of the electric utility industry, but are generally much less sophisticated in risk analysis.

Regulators should keep in mind what the model was designed to do and what necessary simplifying assumptions are built in to it. Careful review of key input data is always necessary and it is wise to remember that even the best of models fed the best available forecasts can provide only informed estimates of future results.

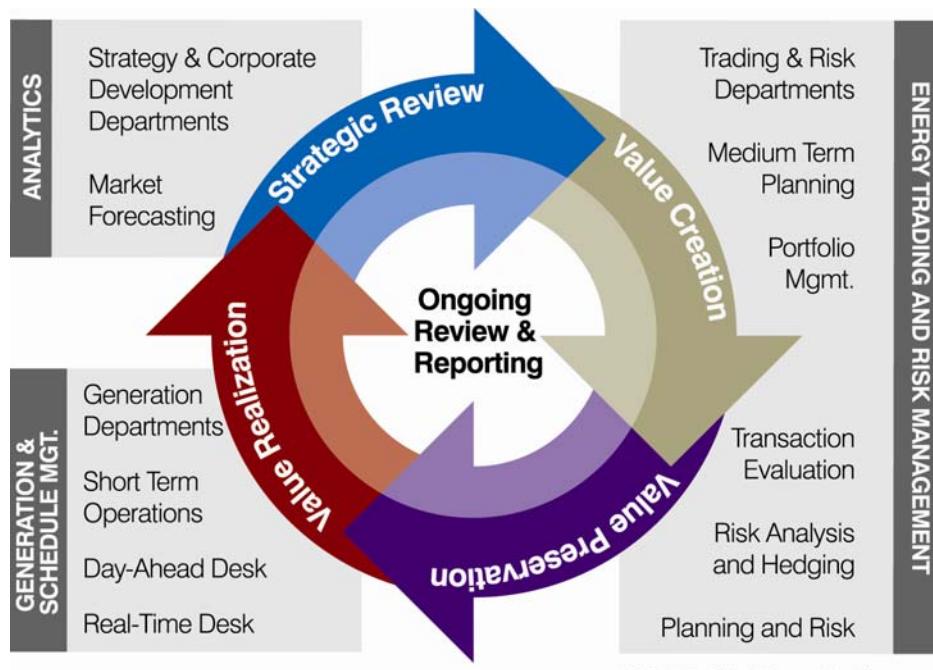
To give some idea of the range of tools for different aspects of electricity portfolio management, we reproduce in Fig. C.1 the product diagram from Global Energy Decisions showing their products and their applicability.⁹⁶

New Energy Associates also offers a suite of products that breaks out the process in a slightly different way. (See Table C.2.)⁹⁷

⁹⁶ <http://www.globalenergy.com/solutions.asp>

⁹⁷ <http://www.newenergyassoc.com/products/>

Fig. C.1. Conceptual Approach of a Sample Portfolio Management Software System (Global Energy Decisions)



SOURCE: Global Energy Decisions

Global Decisions graphic, used by permission

Table. C.1. Conceptual Approach of a Sample Portfolio Management Software System (Global Energy Decisions)

Global Energy Decisions Tools by Category		
<u>Analytics</u>	<u>Energy</u>	<u>Operations</u>
Market Analytics	Front Office Solutions	Generation Management
Market Analytics LMP	Middle Office Solutions	ISO Management
Planning & Risk	Back Office Solutions	Load Forecasting
Capacity Expansion		Plant Management
Strategic Planning		Maintenance Scheduling
		Tariff Analysis

Table. C.2. Conceptual Approach of a Sample Portfolio Management Software System (New Energy Associates)

Strategy and Planning	Trading and Market Operations
PowerBase Suite	Monaco
PROMOD IV Strategist MarketPower	MarketManager Retail Office NOSTRADAMUS
IMPACT	
SENDOUT	Generation Management
	Cockpit

C.2. Load and Price Forecasting

Load forecasting has been done since the beginning of the electric utility industry. The approaches used vary by the time scale involved. Short term forecasts of a day or less are based on typical hourly load patterns for the season and weather forecasts. Forecasts of a few years are generally derived from recent historic data and extrapolated with adjustments for weather and simple external drivers such as population growth and planned DSM programs. Common current practice is to incorporate weather variability in computing confidence intervals for peak load levels. The greatest change has occurred with long range forecasts. The old practice was to plot the historic load values on log graph paper and then draw a straight line into the future. More modern practices look at load growth by customer class and apply econometric methods to develop future values. In some cases the load components are broken down by end-use category. That approach is especially useful for designing and evaluating Demand Side Management (DSM) programs. Over the years most entities have developed and refined their own custom tools for load forecasting.

With the move in recent years to wholesale markets, a number of tools have been developed with integrate load and price forecasting. Some of these are quite sophisticated and consider transmission constraints and locational prices.

There is considerable academic and professional literature on this topic. In recent years most efforts have been focused on short-term forecasting using such techniques as neural networks.

Other sources of information

NERC Load Forecasting Working Group: www.nerc.com/~pc/lfwg.html

Electric Power Research Institute: www.epri.com

Spatial Electric Load Forecasting by H. Lee Willis, Marcel Dekker, Inc.

Table. C.3. Load Forecasting Models

Model	Description	Company
TRM	Time Related Modeling System for time series data in a deregulated market.	Economic Sciences Corporation www.econsci.com
LOADCASTER	Comprehensive load analysis, modeling, forecasting, and settlement software system.	
ESM - ENERGY SERVICES MANAGER	Prospect load analysis, cost of service estimation, bid pricing. DSM project valuation and planning.	
EnerPrise Load Forecasting	Short to mid-term load forecasts for scheduling resources, communicating commitments with an ISO, and planning energy purchases/sales.	Global Energy Decisions www.globalenergy.com
NOSTRADAMUS	A neural network-based short-term demand and price forecasting system	New Energy – Siemens www.newenergyassoc.com
MetrixND	Forecasting techniques, such as neural networks, multivariate regression, ARIMA and exponential smoothing.	Itron www.itron.com
AURORA Price Forecasting	Electric market forecasting tool that captures dynamics and economics of energy markets. Short and long-term forecasts.	EPIS www.epis.com

C.3. Integrated System Planning

Integrated system planning is about finding the right mix of supply and demand side resources that provide low cost and reliable electricity service, while also minimizing risks. This is much like the integrated resource planning that was done by utilities before deregulation. The goals are similar but the available components have changed somewhat.

Table. C.4. Integrated System Planning Models

Model	Description	Company
Electric Generation Expansion System (EGEAS)	Least cost capacity expansion analysis.	Electric Power Research Institute www.epri.com
PowerBase Suite	Power supply and transmission planning with market and risk analysis.	New Energy – Siemens www.newenergyassoc.com
EnerPrise Capacity Expansion	Screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is an economic optimization model that considers resource expansion investments and external market transactions.	Global Energy Decisions www.globalenergy.com
AURORA	Price forecasting, portfolio analysis, capacity expansion, risk and uncertainty analysis.	EPIS www.epis.com
PLEXOS for Power Systems	Operational issues such as scheduling power, optimized unit commitment, transaction and risk evaluation, power station valuation, market analysis, transmission analysis.	Plexos www.plexossolutions.com
Energy 2020	The ENERGY 2020 model is an integrated multi-region energy model that provides complete and detailed all-fuel demand and supply sector simulations.	www.energy2020.org

C.4. Managing Forward Prices & Contracts

An important aspect of portfolio management is organizing and managing market and contract information.

Some of the types of products that could be monitored with software tools include:

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: 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.⁹⁸ 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.

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. This type of option contract is known as a “call” option; a similar option contract that gives the buyer the right to sell a certain quantity of the good to the seller (of the option) at a pre-negotiated price is known as a “put” option.

Flexibility contracts: 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)

Each of these product types offers a different type and degree of pricing and flexibility. The goal of portfolio management may be thought of as finding the optimal trade-off between price and flexibility through 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 create an even mix. The role of software for managing contracts and options is to monitor (perhaps on a daily basis) the cost and riskiness of the inventory of such products and to analyze purchases and sales that might improve the

⁹⁸ The term or time period of a forward contract can be of whatever length the parties choose. It 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. To be “long” in a futures contract means that one has the obligation to buy at a later date, thus coming out ahead if the asset price goes up. To be “short” in a futures contract means that one has an obligation to sell at a later date, thus coming out ahead if the asset price goes down.

tradeoff. If a portfolio includes short positions or options, frequent analysis is needed to choose the best time to fill short positions or to exercise options (if at all).

Many vendors offer applications for this purpose. Table C.5 lists a few fairly widely used in the energy sector. Note also that this category also overlaps some with the risk management tools in the next section.

Table C.5. Software for Forward Price and Contract Management

Model	Description	Company
BookRunner	Analysis for various transaction types and all energy commodities including oil, natural gas, and electricity.	Risk Advisory www.riskadvisory.com
Edur	Application for trading, risk management and operations needs in various commodity markets.	OpenLink www.olf.com/energy/
Epsilon & Entegrate	Integrated risk management, trading and physical commodities scheduling system.	SunGard www.sungard.com
ICTS Symphony	Comprehensive transaction management system to capture, manage, track and process all over-the-counter and exchange traded instruments.	Trade Capture www.tradecapture.com
GasBuyer	Price analysis and decision support tool used for purchasing and hedging natural gas.	Planalytics Inc. www.planalytics.com

C.5. Risk Analysis

In this category are applications focusing on various aspects of risk. The short-term products look at the more quantifiable risks associated with futures contracts and energy markets. A few of the more utility focused tools try to represent in some way the longer term risks. But that is conceptually a more difficult task since there is much greater uncertainty. For longer-term analysis, a scenario-based approach is most commonly used, but the challenge always is to make those scenarios diverse enough to capture a reasonable range of possibilities.

Table C.6. Software for Risk Management

Model	Description	Company
RISKMIN	Least cost capacity expansion analysis.	Electric Power Research Institute www.epri.com
Planning and Risk	Portfolio management to analyze, report, and actively manage assets, including power plants, customer loads, fuels and contractual positions.	Global Energy Decisions www.globalenergy.com
Monaco	Deal capture, advanced risk analytics, multi-commodity portfolio management, real-time credit monitoring and analysis.	New Energy – Siemens www.newenergyassoc.com
Predict!	Database application for recording and managing risks, opportunities, issues and mitigation strategies	Risk Decisions www.riskdecisions.com
Kiodex Risk Workbench	Commodity risk management software.	Sungard Kiodex www.sungard.com/kiodex
NWPCC Portfolio Model	An Excel based model that calculates energy and costs associated with meeting regional requirements for electricity. The model evaluates the cost and risk relationships for a number of alternatives.	Northwest Power and Conservation Council www.nwcouncil.org

C.6. Selecting software:

C.6.1. Selection issues

When selecting software, it is important first to prioritize the objectives and then to evaluate the available options in that context.⁹⁹

- Objectives: How well the software meets the designated needs of the user.
- Involvement: The ultimate users of the software need to be closely involved in its selection and committed to its use.
- Transparency: Are modeling methods and algorithms well documented and visible to users and regulators?

⁹⁹ Some of these criteria are from Marchetti, Anne, Beyond Sarbanes-Oxley Compliance: Effective Enterprise Risk Management, John Wiley & Sons, 2005.

-
- Software Characteristics:
 - Monitoring capabilities
 - Facilitation and documentation of risk assessment, testing, and remediation
 - Built-in version controls
 - Security and access controls
 - Electronic sign-off functionality
 - Audit trail documentation and traceability
 - Ability to customize input fields, reports, and templates
 - Implementation Costs: software, licensing fees, hardware requirements, implementation time, training costs, customization efforts/consulting.
 - Reporting Capabilities: Are the model results available in reports and formats that are easily used and understood?
 - Flexibility: How easily can the software be applied to meet new needs?
 - Support: Does the vendor provide training, fix problems, and update the software as needs change?

C.6.2. Non-Software Cost Considerations

Staffing Costs

When implementing software systems for portfolio management, the biggest cost may very well be labor and training costs for staff using the software. Portfolio management presents a trio of staffing requirements: information technology demands; ability to understand and apply complex economic, statistical, and financial concepts relating to risk management; and understanding any specialized characteristics relating to the electric industry. That last category is quite broad, encompassing, for example, power supply needs, specialized energy products and markets, ISO/RTO requirements, and utility cost recovery or ratemaking. Careful attention to budgeting for staff, staff training (and regular update training), and startup time will be critical.

Hardware Costs

Our experience is that complex models severely task even high end computer hardware. Investments in the fastest computers and largest storage devices available are likely to result in considerable labor savings and faster, more responsive answers to modeling questions. Attention should be paid to backup hardware, as well; large capacity RAID storage devices with hot-swappable drives for off-site backup appear to be the most cost effective solution at this time for high volume data storage. For team use, network attached storage and high speed networking are helpful. The costs for these items are very small compared to the labor and software expenses, but shortchanging them can waste considerable staff time and put critical work at risk.

In summary, regulators considering PM or IRP software acquisition, whether for their own use or by utilities that they oversee, should focus on the prioritized goals and be aware that the largest expense is likely to be for the personnel to properly use the software.

C.7. Model Summary Table

Application	Time Horizon	Input Data and Forecasts	Capacity Expansion Models	Procurement and Scheduling (No Capacity Expansion)
1. Integrated Sys (analytics)	10 to 20 years (long-term)	Forecasts of <ul style="list-style-type: none"> • customer load, • price elasticity, • resource availability, • fuel costs, • resource costs, • risk premiums, • fuel price volatility, • reliability requirements and p • environmental policies and c 	Optimization Models <ul style="list-style-type: none"> • Electric Generation Expan (EGEAS) • EnerPrise Capacity Expan 	<ul style="list-style-type: none"> • PLEXOS for Power System
			Screening/scenario/risk analy <ul style="list-style-type: none"> • PowerBase Suite • AURORA • RISKMIN 	
2. Procurement (Risk Management)	1 to 3 years (short-term)	Energy and fuel price forecasts and futures Load requirements		<ul style="list-style-type: none"> • BookRunner • Edur • Epsilon & Entegrate • ICTS Symphony • Planning and Risk
3. Management Scheduling	Daily to annual (near-term)	Short term load forecasts Resource and transmission availability Fuel and energy prices Environmental conditions		<ul style="list-style-type: none"> • Monaco • Predict! • Kidex Risk Workbench

Appendix D: Risk Measures

Perhaps the most commonly used family of risk measure in portfolio management is Value at Risk and related measures discussed in Section 3 of this report. Others that have been used and which may be of value are summarized in Table 3.1 and explained further here. All depend on development of probability distributions for the cost of the portfolio.

COEFFICIENT OF VARIATION (CV)—This measure is the ratio of the distribution's standard deviation to its mean. It is one way to measure risk relative to return, or in this case, variation in price relative to mean price, measured over a defined period. Tolerance bands can be established around CV.

BETA—Beta is a measure of the systematic risk of a single instrument or an entire portfolio and describes the sensitivity of an instrument or portfolio to broad market movements. A portfolio with a large beta will tend to benefit or suffer from broad market moves more strongly than the market overall, while one with a small beta will swing less violently than the broad market. It is defined as the ratio of the portfolio's covariance with the market divided by the market's variance or Covariance (portfolio, market) / Variance (market). Beta is used to measure volatility of stock returns relative to an index like S&P 500 returns, and one could consider measuring volatility of a resource portfolio's cost relative to volatility of spot market prices. However, it must be remembered that beta does not capture specific risk (the riskiness of the portfolio itself, irrespective of market risk). A portfolio can have a low beta but still be very volatile if its variations are simply not correlated with those of the market.

EXTREME VALUE MEASURES—We use this term as a catch-all for a variety of conceptually straightforward measures of portfolio riskiness. In general, this type of measure is the difference in cost between a portfolio's expected cost and some estimate of its worst-case cost. For example, Northwest Energy and the NPCC measure portfolio riskiness by the difference between its expected cost and average of the worst 10% of its cost's probability distribution.¹⁰⁰

VALUE AT RISK (VAR)—A traditional approach for quantifying risk of investment portfolios.¹⁰¹ VaR measures the downside risk of a portfolio. It is always calculated in the context of a risk level and a planning horizon. In the case of an electricity resource portfolio, VaR would be a measure of the dollar cost increase that has a certain probability (the selected risk level) of occurring over a certain time period (the selected planning horizon). For example, a regulator might be interested in the VaR of a proposed resource portfolio over a one year planning horizon at the 99% risk level. That VaR would tell us the amount of extra cost that would have a 1% chance of occurring over the next year. Or, a VaR at the 90% risk level for a ten year planning horizon would tell us the amount of extra cost that portfolio has a 10% chance of incurring over the next ten

¹⁰⁰ NorthWestern Energy 2005 Electric Default Supply Resource Procurement Plan, available at <http://www.montanaenergyforum.com/plan.html>

¹⁰¹ Harry M. Markowitz, "Portfolio selection," *Journal of Finance*, 7(1), 77-91, 1952.

years. Utilities in California compare portfolios using this type of metric and variations on it.¹⁰²

REVENUE AT RISK (RAR)—Related to VaR, RaR considers a firm that needs a resource to produce a product over the next year. If the cost of that resource increases dramatically and the firm cannot pass on that cost increase to its customers, say because the price had already been agreed upon, then the net revenues could take a big hit. Because of the cost uncertainty of that resource, they have Revenue at Risk (RaR). This firm might want to study the historical price volatility of the resource in question. Suppose this examination of history shows that the one-year 10% RaR is equal to the maximum amount of extra resource cost that the manufacturer can afford to pay without severe damage to its finances, it might choose to purchase a (long) forward contract for all its anticipated resource need for the next year at today's futures price, giving up possible extra profit that would be earned if the commodity price drops, but eliminating that 10% chance of grave damage. Alternatively, the firm might purchase a call option for its resource needs with a strike price that leaves it in the black. The purchase price for that option would be the “insurance premium” for eliminating this risk.

COMPONENT VALUE AT RISK — This measures the marginal contribution to value at risk of each element within the overall portfolio. For a utility’s purposes, this could mean the risk that each additional coal plant, for example, adds to environmental regulation risks. This approach can be especially valuable as a way to provide insight into the risk analysis analogue of avoided cost analysis.

STRESS EXPOSURES — While value at risk might tell a company how much they could lose under the kind of random market fluctuations that make up the broad history of their industry, stress tests help a company understand the larger risks they may also face. (This type of analysis must take into account volatility and correlation spikes.) In general, there are two approaches used. First, one can test the portfolio relative to shocks that have been observed historically and see how the portfolio being considered might fare under a similar shock. 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. It could be especially informative if there are certain large events identified that may or may not occur. An example of a stress exposure would be to test the expected cost and riskiness of various strategies with and without implementation of a proposed market reform or with and without implementation of CO₂ emission limits.

LIQUIDATION VALUE AT RISK — One question many companies wish to answer is the total potential loss that could occur if an asset had to be liquidated. For instance, a utility might try to determine what would happen if it were forced to retire an old coal plant.

MARGIN AT RISK — This measure helps companies understand what margin requirements they may need to provide due to margining agreements. This is important for cash flow management.

¹⁰² CPUC Energy Division, *Workshop Report on Value at Risk, Cash-Flow at Risk, and Other Measures of Portfolio Risk*. June 6, 2003.

CREDIT VALUE AT RISK — A firm's potential credit exposure on individual transactions is the cost of complying with changes to the amount of credit security the firm must supply to creditors. This can be affected by individual transactions or by external conditions that affect the credit obligations of the firm as determined by its total portfolio. For example, long-term contracts that utilities enter can be viewed as liabilities on their books. A credit value at risk calculation can be done to determine how different transactions might affect the utility's return on equity, for instance.

ENTERPRISE-WIDE RISK MEASURES — This is a measure that appropriately aggregates market, credit, regulatory and operational risk for the firm as a whole. Enterprise risk management seeks a balance amongst the various risk components.

COSTS AT RISK – This measures the probability that a portfolio's costs will go up or down by certain amounts over certain time periods. It is of particular interest from a consumer protection perspective.

RATES AT RISK — This measures the potential change in the retail customer's rates as a result of how external fluctuations affect the cost of generation supply portfolio as a whole. This measure, too, is of particular interest from a consumer protection perspective.